Impact of Braess's Paradox and Simultaneous Imposition of Non-Coincidental Transmission Outages on FTR Auctions

by

Israel W. Melendez

A dissertation submitted to The Johns Hopkins University in conformity with the requirements for the degree of Doctor of Philosophy.

Baltimore, Maryland

August, 2017

Abstract

This thesis identifies and resolves an issue caused by Braess's paradox in Financial Transmission Right (FTR) auctions. Braess's paradox in power systems is the situation where adding a new transmission line can reduce the transmission system capacity, and vice-versa. FTRs are auctioned by Regional Transmission Organizations (RTOs) to market parties who wish to hedge uncertain transmission costs. The issue can cause the RTO to over-allocate FTRs and become revenue inadequate which leaves the RTO the dilemma of how to recover the deficit.

An auction process called the simultaneous feasibility test (SFT) limits the FTR awarded to ensure that sufficient congestion rents are collected by the RTO to pay the FTR holders. The problem stems from an SFT approximation coined in this thesis the Simultaneous Imposition of Non-coincidental Transmission Outages (SINTO) that models planned transmission outages concurrently rather than as scheduled. When Braess's paradox applies to FTR auctions, the SFT approximation defies the intuitive assumption that removing transmission lines will reduce transmission system capacity. Thus, two methods are proposed to mitigate the effects of Braess's paradox in FTR auctions. The first is the Chronological Imposition of Planned Transmission Outages (CHIMPO), which ideally models the transmission outages as scheduled but also considerably increases the auction's computational cost. The second method, called the Normally-Operated SINTO (NO-SINTO), is a robust and computationally inexpensive approximation that adds a single set of transmission constraints to the SINTO model.

The five contributions of this thesis are described through simple examples and case study simulation using actual historical FTR auction data. The first establishes, using the SINTO SFT approximation, that the existence of Braess's paradox can lead to revenue inadequacy in FTR auctions. The second demonstrates that modeling SINTO in FTR auctions may aggravate the impact of the paradox. The third offers two alternative FTR auction models (CHIMPO, NO-SINTO) to reduce the risk of revenue inadequacy from Braess's paradox. The fourth demonstrates that the ideal CHIMPO allocation of FTRs is better approximated by the NO-SINTO model than the SINTO model. The fifth indicates that RTOs may practically implement the NO-SINTO approximation on a realistically sized power networks.

ABSTRACT

Academic Advisor and First Reader:

Dr. Benjamin F. Hobbs, Professor

Department of Environmental Health and Engineering

The Johns Hopkins University

Second Reader:

Dr. John J. Boland, Professor Emeritus

Department of Environmental Health and Engineering

The Johns Hopkins University

Third Reader:

Dr. Sauleh Siddiqui, Assistant Professor

Department of Civil Engineering

The Johns Hopkins University

Acknowledgments

Ad Maiorem Dei Gloriam

It goes without saying, that God has truly blessed me. I would not have dreamed that the journey to completing this thesis would involve so many people who have unselfishly helped me along the way. Many have, in some way, contributed to this work and all those not specifically mentioned here, I would like to give you a sincere thank you.

Foremost, I say thank you to my family! First, I would like to thank my beautiful and lovely wife, Christine. This accomplishment would not be possible without you. There are no words to express my gratitude for your sacrifice, patience, and love throughout the years. God blessed me with an incredible partner in life and most remarkable woman.

I would thank my four beautiful children: Lexie, Tommy, Emily, and Russell. I would not have completed this thesis without your love. I am so proud to be your dad!

I am grateful to the rest of my family for their love and support: Mom, Bill, Laura, Tina, Tom, Mary, Betsy, Fred, Ivette, Ivonne, Jerry, Irving, Billy and Pam and their kids. You had faith in me and never questioned whether I would complete my doctorate despite my reservations. You kept me going with your praise and helping me when you could.

I am incredibly indebted to my adviser Dr. Benjamin Hobbs. You do not know how much I respect and admire you. Once again, God blessed me with the most incredibly brilliant but kindest person I know. I am not sure what you saw in me when we met so many years ago but thank you for this incredible journey.

I owe a special thank you to several classmates at Johns Hopkins University who generously helped and encouraged me – Francisco Munos, Marie Chen Nguyen, and Anya Castillo. Also, to those students that prepared me for my Department Qualifying Exam (DQE) and Graduate Board Oral Exam (GBO).

A very special thanks to Dr. Marc Beaudin who greatly helped me in preparing for my DQE and GBO, building a transmission switching model in MATLAB, and with the notation and math representation in Chapters 3, 5, and 6. You truly are God sent!

I would like to thank the folks at Nexant for giving me an iHedge Market Simulator academic license so I could conduct the case study in Chapters 6 and 7. Two incredible people, I would like to personally thank are Dr. Narsi Vempati and Joe Bright. I have enjoyed the hours of collaboration and conversations. I consider both of you close friends, and God has once again blessed me to put you in my life.

ACKNOWLEDGMENTS

I would like to thank some folks at Constellation, namely Steve Wofford and Dale Meyer for allowing me to take this journey. I would also like to thank, Steve McCullough for supporting me over the past four years in this endeavor.

A special thanks go to my dear old friend, Bob Paddy, for having full unwavering confidence in me. Thank you for your guidance last summer to keep me going.

I would like to thank those who wrote reference letters for me to Johns Hopkins University admissions office, namely: Clayton Greer, Russ Philbrick, and Guy Filomeno. You have my gratitude.

I would like to express my appreciation to the wonderful people at the Department of Geography and Environmental Engineering (DOGEE), now the Department of Environmental Health and Engineering. I would like to thank Dr. Ed Bouwer, Dr. Seth Guikema, and Dr. Justin Williams. I would also like to thank the staff who have been so helpful through the years – namely Adena Rojas and Jessica Elroy.

Lastly, I would like to thank Christine Kavanagh at Johns Hopkins University for the wonderful assistance she has so graciously giving me during my enrollment in the program.

Dedication

I dedicate this thesis to my parents, my wife, and my four children. My father, Israel Melendez, was a hardworking man who did not have the opportunity to receive a formal education - this is my tribute to you Dad. My mother, Iris, who taught me to never give up on my dreams - this is for you Mom. To my wife, who is the most amazing woman in the world - I love you! To my children: Lexie, Tommy, Emily and Russell - you are my greatest accomplishment!

Contents

List of Tables

List of Figures

List of Symbols

Mathematical Notation

Note on mathematical notation:

- Sets are shown in the Mathcal font, and indices are in lower-case italic fonts. For example, $k \in \mathcal{K}$ denotes the k^{th} element in the set $\mathcal{K}$. Common sets, such as the set of natural numbers $\mathbb{N}$, or the set of real numbers $\mathbb{R}$, are denoted by the mathbb font.

- Arrays are written in bold, italic, font, whereas elements of an array are written in italics with indices to denote its position. For example, $\boldsymbol{X}$ denotes an array, whereas X_k denotes the k^{th} element in $\boldsymbol{X}$.

- Subscript on variables or sets are indices. If the subscript is in italics, then it is an arbitrary (variable) element, whereas a roman subscript indicates a specific element within a set or variable. For example X_k indicates the k^{th} element of $\boldsymbol{X}$, whereas X_{k} indicates the variable associated with a specific element with the name “k”. Superscript roman text are labels to distinguish variables and sets. For example, X^{One} and X^{Two} are two different variables. Conversely, X_{One} and X_{Two} are two different elements from the same variable $\boldsymbol{X}$.

- Uppercase variables are considered parameters in optimization problems, whereas lowercase letters are considered decision variables in optimization problems. For example, $\boldsymbol{X}$ is a parameter, whereas $\boldsymbol{x}$ is a decision variable.

Indices

i, j Index of buses $\in \mathcal{I}$ (Section 3.5.1)

n Index for the set of auction participants $\mathcal{N}$ (Section 6.3.6)

p Index of time-of-use periods $\in \mathcal{P}$ (Section 6.3.3)

s, s' Index of bids in the set $\mathcal{S}$ (Sections 3.5.2 and 6.3.1)

t Index of transmission outage topology. May be an element of $\mathcal{T}^{\text{CHIMPO}}$, $\mathcal{T}^{\text{SINTO}}$, or $\mathcal{T}^{\text{NO-SINTO}}$ depending on the model under simulation (Section 5)

v Index of the set of interfaces $\mathcal{V}$ (Section 6.3.7)

y Index of settlement points $\in \mathcal{Y}$ (Section 6.3.2)

Parameters

$\boldsymbol{A}^{\text{OTDF}}$ Outages transmission distribution factor, estimates per-unit power flow during unplanned transmission outages [unitless] (Section 6.3.8)

$\boldsymbol{A}^{\text{PTDF}}$ Power transfer distribution capacity, which describes the effect of each injection and withdrawal on each line [unitless] (Section 6.3.7)

LIST OF SYMBOLS

$\boldsymbol{B}$ Susceptance matrix, with units approximated as [MW/rad] (Section 3.5.1)

$\boldsymbol{C}^{\text{Bid}}$ Value of bids [$/MW] (Section 3.5.2)

$\boldsymbol{C}^{\text{Cost}}$ Cost of generating power at a bus [$/MW] (Section 3.5.1)

$\boldsymbol{F}^{\max}$ Bid quantity [MW] (Section 3.5.2)

$\boldsymbol{G}^{\min}, \boldsymbol{G}^{\max}$ Minimum and maximum power that can be generated at buses, respectively [MW] (Section 3.5.1)

$\boldsymbol{L}$ Load at buses [MW] (Section 3.5.1)

$\boldsymbol{M}$ FTR Mapping matrix, or the per-unit power flow distribution on buses due to each bid [Unitless] (Section 3.5.2). Further described in Section 6.3.2

$\boldsymbol{M}^{+}$, $\boldsymbol{M}^{-}$ Per-unit power injection and withdrawal on buses due to each bid, respectively [Unitless] (Section 6.3.2)

$\boldsymbol{O}$ Hedge types (*i.e.*, Options and Obligations) associated to each bid, where $\boldsymbol{O} \in \{\text{Opt}, \text{Obl}\}$ (Section 6.3.1). Further described in Section 6.3.5

$\boldsymbol{P}$ Time-of-use periods (*i.e.*, peak-weekday, peak-weekend, offpeak) associated with each bid, where $\boldsymbol{P} \in \{\text{PeakWD}, \text{PeakWE}, \text{Offpeak}\}$ (Section 6.3.1). Further described in Section 6.3.3

$\boldsymbol{Q}^{\text{emer}}$ Maximum allowable power flow during unplanned transmission outages [MW] (Section 6.3.8)

$\boldsymbol{Q}^{\text{Int}}$ Maximum power transferred between geographic region, known as interface limit [MW] (Section 6.3.7)

$\boldsymbol{Q}^{\min}, \boldsymbol{Q}^{\max}$ Minimum and maximum power that can be transferred on lines, respectively [MW] (Section 3.5.1)

$\boldsymbol{W}$ Weight of each bid due to size of time blocks, when considering time-of-use bids [unitless] (Section 6.3.3)

$\boldsymbol{Y}^{+}$, $\boldsymbol{Y}^{-}$ Vector of source and sink settlement price points in the bid data, respectively, where $\boldsymbol{Y}^{+}, \boldsymbol{Y}^{-} \in \mathcal{Y}$ (Section 6.3.1). Further described in Section 6.3.2

$\boldsymbol{Z}$ Budget constraint for auction participants [$] (Section 6.3.6)

ϕ, η Respective parameters relating to the exposure of Obligations [unitless] and [$/MW] (Section 6.3.6)

Sets

$\mathbb{N}$ Set of natural numbers

$\mathbb{R}$ Set of real numbers

$\mathcal{C}$ Set of contingencies [unitless] (Section 6.3.8)

$\mathcal{I}$ Set of all buses (Section 3.5.1)

$\mathcal{I}_i^{\text{Conn}}$ Set of buses connected to bus i, $\mathcal{I}_i^{\text{Conn}} \in \mathcal{I}$ (Section 3.5.1)

$\mathcal{I}_y^{\text{SPP}}$ Set of buses associated with settlement point y, $\mathcal{I}_y^{\text{SPP}} \in \mathcal{I}$ (Section 6.3.2)

$\mathcal{L}_v^{\text{Int}}$ Set of lines containing interface v (Section 6.3.7)

$\mathcal{N}$ Set of auction participants (Section 6.3.6)

$\mathcal{P}$ Set of time-of-use periods, where $\mathcal{P} = \{\text{PeakWD}, \text{PeakWE}, \text{Offpeak}\}$ (Section 6.3.3)

$\mathcal{S}$ Set of all bids (Section 3.5.2)

$\mathcal{S}_s^{\text{24hr}}$ Complementary bids that complete 24-hour bids associated s, $\mathcal{S}_s^{\text{24hr}} \subseteq \mathcal{S}$. For example, if bids 1,2,3 belongs to a 24-hour bid, then $\mathcal{S}_1^{\text{24hr}} = \{2, 3\}$. (Section 6.3.3)

$\mathcal{S}_n^{\text{Bid}}$ Set of bids submitted by auction participant n, where $\mathcal{S}_n^{\text{Bid}}$ are partitions of $\mathcal{S}$ (Section 6.3.6)

$\mathcal{S}^{\text{Fixed}}$ Set of pre-awarded bids, $\mathcal{S}^{\text{Fixed}} \subseteq \mathcal{S}$, which fix bid award $F^{\max}$ values (Section 6.3.1)

$\mathcal{S}^{\text{Obl}}$, $\mathcal{S}^{\text{Opt}}$ Set of bid Obligations and Options, respectively, where $\mathcal{S}^{\text{Obl}}$ and $\mathcal{S}^{\text{Opt}}$ are partitions of $\mathcal{S}$ (Section 6.3.5)

$\mathcal{T}^{\text{CHIMPO}}$ Set of chronological imposition of planned outage topologies (Section 5)

$\mathcal{T}^{\text{NO}-\text{SINTO}}$ Set of normal operation (NO) and simultaneous imposition of transmission outage (SINTO) topologies. The set is defined as $\{\text{NO}, \text{SINTO}\}$ (Section

5)

$\mathcal{T}^{\text{SINTO}}$ Set of simultaneous imposition of transmission outage (SINTO) topology. The set is defined as {SINTO} (Section 5)

$\mathcal{V}$ Set of interfaces related to generic constraints (Section 6.3.7)

$\mathcal{Y}$ Set of all Settlement points (Section 6.3.2)

Variables

$\boldsymbol{\theta}$ Bus angles [rad] (Section 3.5.1)

$\boldsymbol{f}$ Awarded financial transmission right bid quantities [MW] (Section 3.5.2)

$\boldsymbol{g}$ Quantity of power generated at buses [MW] (Section 3.5.1)

$\boldsymbol{q}^{\text{Bus}}$ Net power injection into buses [MW] (Section 3.5.1)

$\boldsymbol{q}^{\text{Line}}$ Quantity of power transferred in lines [MW] (Section 3.5.1)

List of Abbreviations

ARR	Auction Revenue Rights
ATC	Available Transfer Capability
CAISO	California Independent System Operator
CHIMPO	Chronological Imposition of Planned Outages
CRR	Congestion Revenue Right (similar to FTR)
DA	Day-ahead
DC	Direct Current
ERCOT	Electric Reliability Council of Texas
FERC	Federal Energy Regulatory Commission
FTRs	Financial Transmission Rights
FTRWG	Financial Transmission Rights Working Group
IGO	Independent Grid Operator
IMM	Independent Market Monitor
ISO	Independent System Operator
ISONE	Independent System Operator New England

LIST OF ABBREVIATIONS

JETRA	Joint Energy and Transmission
LMP	Locational Marginal Price
MCC	Marginal Congestion Component
MEC	Marginal Energy Component
MISO	Midcontinent Independent System Operator
MLC	Marginal Loss Component
NEISO	New England Independent System Operator
NERC	North American Electric Reliability Organization
NMMS	Network Model Management System
NO-SINTO	Normal Operation - SINTO (see SINTO)
NYISO	New York Independent System Operator
OASIS	Open Access Same-time Information System
OATT	Open Access Transmision Tariff
OPF	Optimum Power Flow
OTDF	Outage Transfer Distribution Factor
PAR	Phase Angle Regulator
PHALC	Parallel High Admittance Low Capacity
PJM	Pennsylvania-New Jersey-Maryland Interconnection
PTDF	Power Transfer Distribution Factor
PTP	Point-to-Point
RT	Real-time

LIST OF ABBREVIATIONS

RTO	Regional Transmission Organization
SCED	Security Constrained Economic Dispatch
SCUC	Security Constrained Unit Commitment
SF	Shift Factor
SFT	Simultaneous Feasibility Test
SINTO	Simultaneous Imposition of Non-coincidental Transmission Outages
SMD	Stardard Market Design
SPP	Southwest Power Pool
SPP	Settlement Point Price
TCC	Transmission Congestion Contract
TCR	Transmission Congestion Right
TLR	Transmission Loading Relief
TRR	Transmission Reconfiguration Right

Chapter 1

Introduction

1.1 Background

> "Transmission rights stand at the center of market design in a restructured electricity industry" [1].

The main goals of electric power restructuring are to provide industry participants with better incentives to reduce their costs and to introduce innovations that increase the social welfare, or more precisely, to lower the cost of electricity provision by opening power generation to competition [2]. The literature that analyzes and quantifies the benefits of electricity market designs is extensive [1, 3–18]. While in theory, each market design may be economically efficient, its benefits may not be fully realized in practice due to its complexity or difficulty to implement in a manner that is publicly acceptable and robust against gaming. The translation of broad policy design concepts to practicable and enforceable regulation often lead to inefficient implementation, whose impact vary widely. One common issue concerning the design of electricity markets is the fair access to the transmission system.

Due to physical laws governing power transmission and congestion on power transfer, the value of electricity can vary based on location. In a deregulated electricity market, it is considered economically efficient to price electricity to reflect the value of electricity at each bus[1], such that each bus will have a locational marginal price (LMP) for electricity. Locational marginal pricing is used in most American bulk power markets to ensure that consumers fairly pay generators for electricity provision, both in real-time markets and in day-ahead markets. When there is a difference in LMP between two nodes, an incentive exists for transmitting power from the cheaper bus to the more expensive bus until the prices converge. However, when this is impossible (*e.g.*, congestion or Kirchkoff's laws), financial transmission rights (FTRs) have been suggested as a financial instrument to capture the cost difference.

A congested power system may purchase power from a generator at a cheap node and resell power at an expensive node at a net positive revenue, called congestion rent. While this practice is profitable for merchant transmission lines, independent system operators (ISOs)[2] are expected to be impartial and to return congestion rents to market participants as fairly as possible. An FTR is a financial instrument designed to address this issue by hedging FTR holders from congestion, by compensating them

[1] A power system bus, also known as a node or busbar, is a piece of electrically conductive metal that allows a common point for connection of power system equipment, such as power lines.

[2] A regional transmission organization (RTO) or independent system operator (ISO)[3] is an entity that administrates and operates centralized power markets.

(based on nodal price differences) an amount equal to the congestion rent, thereby putting the system operator back in an impartial position.[4] FTR recipients pay or are compensated the congestion rent. The objective of the FTR auction is to maximize the economic value of allocating FTRs, subject to network constraints, where each bid contains information such as quantity and price of power.

However, the FTR system is not without flaws. Even today, we face pricing difficulties in electricity markets, as described Joskow et al. in 1997 [20]:

> "We must get transmission pricing right to decentralize competitive generation supply decisions efficiently over time and space on an AC network" [20].

When the FTR auctioneer over-allocates the amount of FTRs, the market operator may owe more money to FTR holders than they make from congestion rents, which causes the FTR auctioneer to be revenue inadequate. One of the biggest issues facing the centralized power markets is that of maintaining revenue adequacy of FTR systems. Revenue adequacy is desirable so that the FTR holders can be paid without the ISO losing money. This issue is described in detail in Section 2.2, with simple numerical examples in Chapter 4. Hogan [1] demonstrates that, under certain

[4]Congestion rent can be calculated as the product of the power flow and price differences between two points [19]. Some markets minimize the as-bid cost of generation, accounting for both congestion and transmission resistance losses; thus, congestion is not the sole factor that can cause price divergence between busses. In this case, the LMP is equal to the sum of the marginal energy component (MEC), the marginal loss component (MLC), and the marginal congestion component (MCC): LMP = MEC + MLC + MCC. For these markets, the congestion rents are collected from the MCC instead of the LMP differences. For simplicity, the dispatch examples and formulations provided in this proposal assume no transmission losses, such that the congestion cost is solely due to LMP differences.

conditions, revenue adequacy can be achieved by ensuring FTRs pass a simultaneous feasibility test (SFT): if the market operator limits FTR allocations to the capacity of the transmission system, the convex set of constraints accurately represents the network during operations, then the FTR market system would be revenue adequate. While it is known that revenue adequacy is desirable, the methods of recovering from revenue inadequacy in FTR auctions is still debated. This issue is presently of great concern to RTOs, stakeholders, and regulators [21].[5]

The most common method of acquiring FTRs is through monthly FTR auctions run by the market operator (*i.e.*, FTR auctioneer) for the entire following month, unlike power transactions that may have 15-minute or hourly resolution. This practice is called calendar-strip sales.[6] Auction participants need to account for network topologies occurring during the auction period when submitting their bids. The current industry practice is to model all transmission outages concurrently in the SFT and throughout the entire FTR auction period, known as the simultaneous imposition of non-coincident transmission outages (SINTO). However, this can be problematic because auction participants must submit bids with a monthly resolution, while knowing that the transmission network topology may change several times during that period (*e.g.*, due to repairs for transmission line, transformer, breaker, etc.), which may fail the SFT. Ideally, FTR auctions could be held at a higher time resolution (*e.g.*,

[5] Discussed in Section 2.2

[6] A calendar strip is a product where the quantity is typically based on a sequence of hours that are bundled together for sale. FTRs are sold by calendar strips. Calendar strip sales are also called life term [22] or validity period [23].

each settlement period)[7] based on the transmission capacity available in each period, rather than to treat all maintenance outages as if they occur concurrently for the entire month. However, current market rules in all formal U.S. markets only allow future FTRs to be auctioned off in monthly calendar strips. For example, if a auction participant's 1-MW bid clears for a 30-day month, they purchased 1 MW $\times$ 24 hours/day $\times$ 30 days/month, or 720 MWh/month. Alternatively, non-coincidental outage models would allow each network topology, resulting from planned outage schedules that do not perfectly overlap, to be considered in FTR auctions. The latter better represents the actual availability of transmission and in general, would result in different FTR distributions. The operation of the SFT is illustrated with numerical examples in Chapter 4.

The origin of using the single-topology model is not known; however, it is ubiquitously practiced in the industry in FTR auction modeling [24–27].[8] As explained in Section 2.1, there are two reasons for this practice: computational simplicity and a naive (and, as this thesis shows, mistaken) expectation that considering all outages together would result in a conservative (smaller) allocation of rights, thereby ensuring that the market operator remains revenue adequate. The criteria for transmission outage inclusion that RTOs use for the single-topology SINTO SFT approximation are shown in Table 3.1. As described in Section 3.4, one possible reason that the

[7]Many day-ahead power markets settle hourly.

[8]Prior to centralized LMP markets with FTR auctions, the simultaneous outage assumption was widely used to model outages when defining the feasible amount of physical transmission service or rights that could be provided. [28–35]

practice was adopted was to reduce the number of constraints. For example, considering two distinct network configurations on different days would double the number of constraints because the flows from a given set of rights would have to be calculated for the two distinct configurations. Reducing the size of the problem was desirable, or even necessary, due to limitations in computer software and hardware capabilities at the time.[9]

In many instances, the SINTO practice may yield conservative solutions that avoid FTR overallocation [35, 36] by awarding FTRs based on a system with a smaller capacity. However, as noted in [37, 38], removing a transmission element may in fact increase the capacity of the system. This phenomenon is known as Braess's paradox, which was first described for transportation systems [39]. If Braess's paradox results in an increase in FTR allocations using the SINTO model, it would be inconsistent with the assumption that SINTO conservatively reduces FTR allocations for the market operator to remain revenue adequate. The presence of Braess's paradox in SINTO-based FTR auctions would affect FTR prices, availability, and distribution with attendant impacts on market efficiency (net economic benefit-maximizing solution), revenue adequacy, and the financial position of partipants in wholesale markets. Note that Braess's paradox is a system-level phenomenon: removing one line may increase or decrease system capacity under different circumstances. However, it is possible, in some circumstances, to localize Braess's Paradox to a specific line or

[9]This is considering the large number of contingencies that would have to be analyzed.

set of lines in the system, where the effect is more commonly observed.

Consider, for example, a case where there are two sets of scheduled outages at different times of month. The market operator, who is in a conservative position to avoid revenue inadequacy, allocates FTRs with the assumption that both outages occur simultaneously. If the modeled topology does not exhibit Braess's paradox, SINTO limits FTR availability such that more FTRs could have been sold. This may be a sub-optimal solution, but would guarantee revenue adequacy. However, the assumption of revenue adequacy does not hold when we consider a system that exhibits Braess's paradox. It is possible that, by modeling both sets of outages simultaneously, that the system capacity increases, thereby leading the market operator's "conservative" model to over-allocate FTRs and become revenue inadequate.

To make the situation more complex, the effects of Braess's paradox are locational: it is possible for SINTO modeling increases capacity in one region while decreasing in another. As a result, it is possible, due to Braess's paradox and the fact that FTRs are locational, that the market operator over-allocates FTRs in one region and under-allocates them in another. Thus, due to Braess's paradox, it is difficult to predict whether the market operator will be revenue adequate.

This research investigates the impacts of Braess's paradox and SINTO in calendar strip sales on the revenue adequacy of market operators. The combination of how FTRs are auctioned (calendar strips), Braess's paradox, and SINTO may reduce the efficiency of the market by not providing the set of FTRs that maximizes benefits to users while still satisfying the revenue adequacy condition. This thesis investigates how the combination of Braess's paradox, SINTO, and FTR calendar strip sales impacts revenue adequacy and develops new FTR auction formulations that will reduce their impact on revenue inadequacy while maintaining computational efficiency. More precisely, the objectives of the research are as follows:

1. Investigate the impact of SINTO and Braess's paradox upon FTR auction results, showing that together with FTR calendar strip sales they can lead directly to revenue inadequacy in realistic situations.

2. Provide two reformulations and/or practices in FTR auctions that can eliminate or greatly mitigate the potential impacts of hypothesized over-conservative awards of FTRs by SINTO and/or the over-generous award of rights if Braess's paradox is important in real systems.

3. Conduct a case study to find evidence for which of Braess's paradox or over-conservatism is a greater problem with the widely used SINTO auction and concurrently test whether two practical reformulations yield rights allocations that are closer to the allocation that would result if the actual daily distribution of network outages were to be considered when making monthly allocations.

4. Determine whether the two practical reformulations can be implemented by an RTO.

This research is relevant because it addresses a correctable issue that impacts the distribution of transmission rights and pricing in all current centralized power markets. Addressing this issue would reduce revenue inadequacy and distortion[10] in FTR award distributions and FTR clearing prices – both of which impact market efficiency.

1.2 Dissertation scope

The structure of the thesis is as follows. In the present chapter, the scope of this dissertation is formally introduced, namely, how Braess's paradox and the SINTO practice used in FTR auctions as FTR products are awarded (calendar strip sales) leads to revenue inadequacy. Moreover, it describes the research objectives. In addition, this section describes the arrangement of this dissertation.

Chapter 2 provides a synopsis on the evolution of power markets, from bilateral markets with physical transmission rights to LMP markets and FTRs, and develops a hypothesis on how and why the SINTO practice is part of the FTR auction modeling practice. In addition, this chapter reviews known causes of FTR underfunding and revenue inadequacy and how these are currently managed in current markets. Finally, the chapter reviews the literature relevant to the proposed research, which includes LMP market design, FTR development, and FTR revenue adequacy.

Chapter 3 is a broad chapter covering necessary concepts. It contains detailed

[10]Distortion in this context is defined as the path-specific change in FTR awards due to additional transmission capacity caused by Braess's paradox and SINTO.

background information and a baseline model for understanding the subsequent work. Section 3.2 provides a simple example to illustrate how LMP arises when the transmission network is congested. In Section 3.3, Braess's paradox is presented from its discovery in transportation system to its application in power systems. Braess's paradox explains situations where removing a transmission element increases the transmission capacity of the system. Section 3.3 concludes by examining two simple circuits that exhibit Braess's paradox: the first is a Wheatstone bridge circuit and the second has parallel circuits with one circuit having higher admittance and lower capacity than the other circuit (parallel high admittance low capacity, PHALC). Admittance is a measure of how easily a circuit or device will allow a current to flow. After explaining these circuits, the two circuits are combined in Chapter 4 to create an example that numerically illustrates the problem pertaining to revenue inadequacy. Section 3.4, explains SINTO in power systems and the possible origin of the practice. Chapter 3 concludes in Section 3.5 by reviewing two formulations: an LMP energy dispatch formulation and a general FTR auction formulation. The dispatch formulation is used in later examples to provide LMPs resulting from energy dispatch, and the LMP differences are used to simulate the payouts (settlements) from the allocated FTRs. Likewise, the FTR formulation is used in an example FTR auction to simulate derived FTR clearing prices. In addition, the FTR auction formulation is modified to mitigate FTR over-awarding due to the combined impact of Braess's paradox, SINTO, and FTR calendar strip sales. This proposal is an important contribution of this thesis and is elaborated upon in later chapters.

Chapter 4 derives how revenue inadequacy occurs due to Braess's paradox, SINTO, and FTR calendar strip sales. This is accomplished by modeling and comparing two cases – the first using the SINTO practice and the second by modifying the FTR auction to include constraints that represent each transmission configuration that occurs during the period. The contribution of this chapter is the identification of the correctable issue that causes revenue inadequacy.

In Chapter 5, two FTR auction formulations are developed that remedy the effects of Braess's paradox in FTR auctions – the two models are practical and readily implementable in actual FTR auctions. The first improves the SFT approximation by modeling all unique outage configurations as a result of the planned transmission outage schedule and is named the chronological imposition of planned transmission outages (CHIMPO). The second formulation is called the normal operation – simultaneous imposition of non-coincidental transmission outages (NO-SINTO), which is a practical modification to SINTO that mitigates Braess's paradox and improves the model run-time performance.

Chapters 6 and 7 constitute a case study that contributes evidence that Braess's paradox and SINTO do impact real FTR auction results. By applying ERCOT FTR auction data to the iHedge® FTR market simulator (a commercial FTR auction software package also used by ERCOT for CRR,[11] it was possible to elucidate the

[11] In ERCOT, FTRs are called congestion revenue rights or CRRs.

role of Braess's paradox in real FTR auctions. iHedge is reconfigured to the two practical formulations in Chapter 5, namely the CHIMPO and NO-SINTO formulations. The objective function values of these two formulations are compared to the SINTO FTR auction and to another case that is similar to a SINTO FTR auction without transmission outages included. Chapter 6 provides the rationale for selecting ERCOT for the case study, describes ERCOT's CRR auction process and iHedge (and configuration for practical formulations), describes the model data preparation, and provides case study research questions and model run methodology. Chapter 7 answers the case study questions posed in Chapter 6 and provides the case study results, analysis, and findings. In addition, an assessment is offered on the feasibility of ERCOT adopting the practical formulations by comparing computational run-time performance and analyzing the difficulty of preparing the model runs.

Chapter 8 concludes the dissertation by summarizing the contributions made in the preceding chapters and suggests areas of future research.

Chapter 2

Literature Survey

This chapter has four objectives. The first objective is to provide background on how the practice of simultaneously modeling non-coincidental transmission outages (SINTO) became widespread in Financial Transmission Rights (FTRs) auction processes. The second objective is to provide a historical overview of FTR funding to give an indication of RTO performance in managing FTR revenue adequacy. The third objective is to explain the known causes of FTR underfunding and the methods RTOs adopted to manage the shortfalls. Finally, the chapter concludes with a review of the academic literature relevant to financial transmission rights and theoretical causes of revenue inadequacy.

2.1 Background

In 1996, Federal Energy Regulatory Commission (FERC) Orders 888 [40] and 889 [41] mandated the deregulation of the power industry – unbundling vertically integrated utilities into unregulated generation, regulated transmission, and distribution companies. Central to the order was non-discriminatory access to the transmission system. To provide non-discriminatory access to the transmission system, the orders called for the creation of the Open Access Same Time Information System known as OASIS. OASIS provided a centralized portal so that all customers were treated equally and had the same access to transmission information and capacity available for sale. Transmission service is the leasing of transmission capacity from the transmission owners through entities called transmission service providers.

Before implementation of Locational Marginal Price (LMP) markets with FTRs, transmission service was a physical capacity right where a portion of transmission system's line capacities was reserved. The physical transmission service was sold based on the "firmness" of the service whereas the firmer the transmission service, the lower the possibility of curtailment. Of course, transmission customers would pay more for firmer service. Transmission service was also sold by term: annual, monthly, weekly, daily, and hourly. The firmness of the transmission service increased with the length of the term so that the system operator would curtail a shorter term service before a longer term one. Lastly, transmission service was sold as either point-to-point or network service. Point-to-point transmission service was sold for transactions between control areas.[1] Sometimes these transactions involved "wheeling" power [42] through a control area that neither had the generator (source) or the designated load (sink). In addition to point-to-point service, a trader would have to purchase transmission service within a control area to move the power from either the generator to the control area boundary or from the boundary to the load. This transmission service is known as Network Transmission Service. Most of the network transmission service is sold to the legacy electric utility customers for transmission service inside their control area from their legacy utility generators known as Designated Network Resources [43, 44].

OASIS sites were required to post the amount of transmission capacity available for sale, Available Transfer Capability (ATC), to other control areas (legacy transmission service territories of electric utilities) - for power traders and marketers to determine available transmission capacity. Engineers used power flow analysis to determine available transfer capability and developed methodologies based on how transmission service was sold. A capacity accounting system emerged based on power flow studies. For example, annual transmission service was studied using twelve base cases (power flow models) – one representing each month. This resulted in the problem of how to model non-coincidental transmission outages, each of which tends to last days rather than a full month. It is not known why the practice was adopted, but ultimately transmission engineers chose to simultaneously model non-coincidental transmission

[1] Today, Control Areas are called Balancing Authority Areas.

outages using SINTO-type models. Although this practice was not collectively decided upon, it has become the *de facto* good utility practice by utilities [24–35,45–47]. One possible reason may be due to lack of awareness of Braess's paradox, or perhaps the low-frequency of Braess's paradox caused it to be ignored in models. It is reasonable, however, to conclude that SINTO was a conservative measure to avoid overselling transmission service by reducing the available capacity.

In 1994, Hogan proposed a nodal market design based on LMPs and financial transmission rights, which was adopted by FERC's Order 2000 [48]. LMP-based markets were first proposed by Schweppe et al. [4, 5]. A more thorough explanation of these academic works is provided in Section 2.5. Order 2000 attempted to implement a Standard Market Design (SMD) that included a day-ahead LMP market, a real-time LMP market, and financial transmission rights. Additionally, SMD initiated a centralized unit commitment process, known as Security Constrained Unit Commitment (SCUC) and a dispatch process known as Security Constrained Economic Dispatch (SCED). A key challenge for FERC included the compensation of transmission service customers with equivalent transmission rights in an LMP market. In LMP markets, the economics of the generators determine which generating units operate to use the transmission capacity. In other words, in LMP markets, generators that cause congestion are disincentivized from running, as it would decrease the clearing price. By contrast, in physical rights markets, the "firmness" of service determines the transactions cut to relieve the constraint. Note the inefficiency: if a line becomes congested, a lower cost generator can be curtailed if the higher cost generator has firmer transmission service than a lower cost generator. This inefficiency is remedied in an LMP market; thus the concept of "firmness" of the transmission service is no longer relevant.

The solution was to replace physical transmission service reservations with FTRs through an FTR allocation process. FTRs credit the market participant the congestion charges incurred if there was congestion between the generator and the load (point-to-point) it is serving, thereby financially hedging the transaction. The excess transmission capacity after the FTR allocation process would be made available to the market through FTR auctions. FTR auctions require a simultaneous feasibility test to maintain revenue adequacy that limits the number of FTRs to the available transmission capacity. Current practices in all RTO/ISO markets model non-coincidental transmission outages simultaneously (SINTO) in assessing system feasibility.

Revenue adequacy is a term used in the power industry to indicate when the RTO can collect enough congestion rents to pay all of its FTR holders. More specifically, Hogan defines it as follows: "the system is revenue adequate if the revenues collected from the economic dispatch in the form of congestion payments are sufficient to fully fund payments for the FTRs" [49]. Although Hogan provides theoretical proof that the FTR model is revenue adequate under certain assumptions, in actuality, most ISO/RTOs are not [50], [51] or have adopted administrative mechanisms to manage the discrepancy. To address this issue, Hogan provides insight into the drivers of the inadequacies [49]. Many of these drivers are caused by uncertainties that are not controllable. For example, a forced (unplanned) transmission line outage due to equipment failure can cause congestion. In this case, the capacity limitation is not modeled in the FTR auction, and thus, FTRs are over-awarded. This causes a discrepancy between the total congestion rents collected to pay the FTR holders. Other causes of revenue inadequacy are discussed in Section 2.2. This research will not address these uncontrollable events that lead to revenue inadequacy but instead will focus on how simplified (simultaneous) modeling of maintenance outages together with Braess's paradox can also result in revenue inadequacy.

2.2 Revenue inadequacy problems in today's FTR markets

This section presents the initial motivation for this research by presenting an overview of RTO FTR funding performance in the United States centralized power markets prior to 2015. See Figure 2.1 to reference the geographical boundaries of the seven U.S. centralized power markets discussed below. The terminology used to describe the measurement of revenue adequacy, limits and assumptions used in the simultaneous feasibility test and settlement mechanisms used for funding FTR payments differ among the markets; therefore, there are differences in how revenue adequacy metrics are reported by each RTO. The objective of this section is to show that revenue adequacy performance is a concern that is actively monitored by all U.S. RTOs and historically is, in almost all RTOs, an underfunding issue that RTOs must address.

According to [52], "The purpose of the SFT is to preserve the economic value of FTRs to the FTR holders by ensuring that all FTRs awarded can be honored." Thus addressing revenue inadequacy issues begin by improving the SFT (which is the objective of this thesis). When the economic value of the FTRs are not preserved (by under collecting sufficient congestion rents), they weaken FTR values and create uncertainty affecting the efficiency of the market [52, 53]. Conversely, the RTO would receive a surplus (by over collecting congestion rents) and also maintain the value of the FTRs if the RTO does not allocate sufficient FTR quantities. However, this too is problematic because it creates a lost opportunity cost by not making available the full capability of the transmission system. RTOs bear the responsibility for managing these two situations.

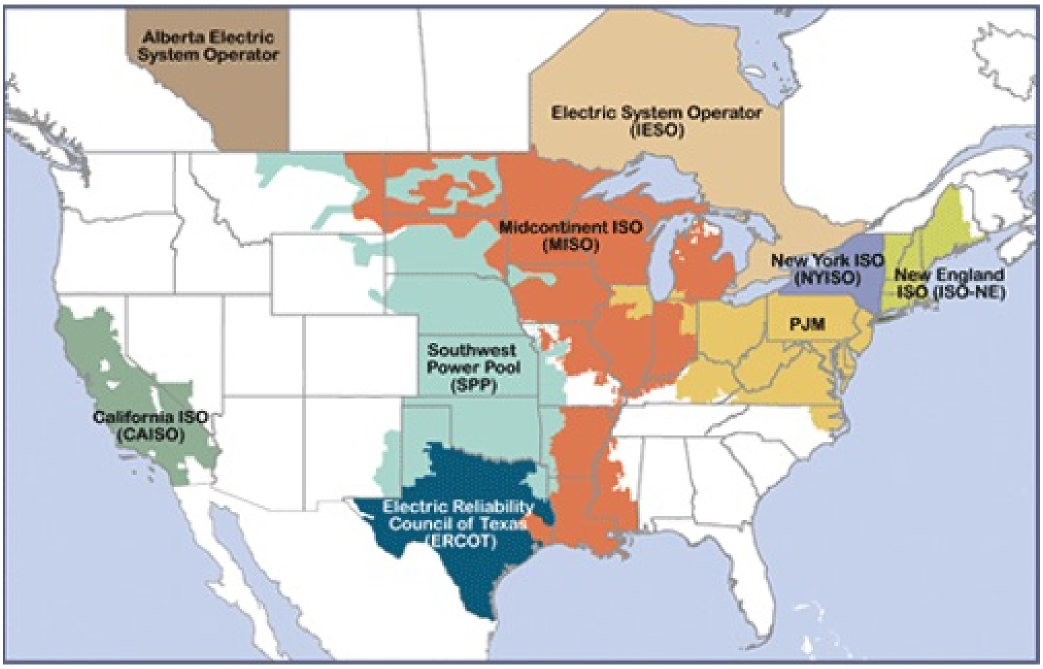


Figure 2.1: Map of RTOs-ISOs in the United States [54]

2.2.1 Pennsylvania-New Jersey-Maryland Interconnection

The PJM[2] interconnection is the largest power market in the United States. It has a highest peak demand of 165,492 MW [56].[3] In 1997, it was the first centrally dispatched U.S. power market to implement LMP [57, 58] and in 1998 implemented their FTR auction market [59]. This being the case, PJM is closely scrutinized by the power industry as a prototypical model for other power markets to learn from and

[2]PJM started in 1927 when three utilities from New Jersey and Pennsylvania formed an integrated power pool. After Baltimore Gas and Electric Company and General Public Utilities joined in 1956, the pool was renamed the Pennsylvania-New Jersey-Maryland Interconnection or PJM. PJM became an ISO in 1997 and an RTO 2001, and since then the RTO has grown to include other utilities from Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia [55]

[3]Occurred in July 2011

being the oldest U.S. LMP market and first to implement FTRs it has the longest history managing revenue adequacy.

PJM manages revenue inadequacy by pro rata reduction of the FTR payments to the FTR holders. Figure 2.2 displays the FTR annual percent payout since FTRs were first implemented by PJM. The FTR annual payout percentage is equal to the total congestion rents collected divided target FTR payments over a year whereas the target payment is the fully funded FTR payment equal to the total number of FTR times the corresponding price difference between the sink LMP minus the source LMP.

$$\text{Annual FTR Payout Percentage} = \frac{\text{Total Congestion Rents}}{\text{Target FTR Payments}} \times 100\%$$

where,

$$\text{Target FTR Payments} = \sum_{s \in \mathcal{S}^{\text{Fixed}}} q_s^{\text{FTR}} \times (\pi_s^{\text{LMP,Sink}} - \pi_s^{\text{LMP,Source}})$$

where $s \in \mathcal{S}^{\text{Fixed}}$ denote the set of previously awarded FTRs, q_s^{FTR} is the quantity of transmission rights awarded for bid s [MW], and $\pi_s^{\text{LMP,Source}}$ and $\pi_s^{\text{LMP,Sink}}$ denote the locational marginal prices at the source and sink settlement points for bid s [\$/MW].

Despite using a simultaneous feasibility test to release FTRs, the FTR payments have been reduced in ten of the sixteen years with several recent years (2011 to 2014) experiencing very large percent reductions of 19%, 31.7%, and 27.2% respectively. During these years the revenue inadequacy amounted to \$192, \$288 and \$679

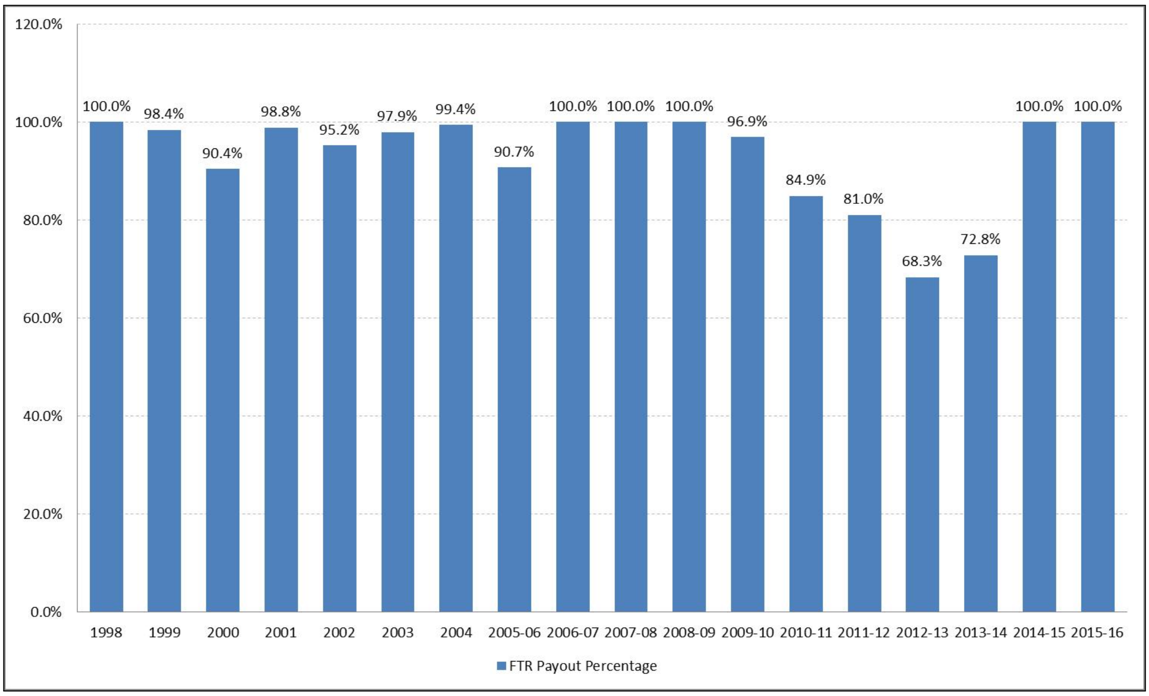


Figure 2.2: Historical PJM FTR payout percentage [60]

million dollars respectively. Figure 2.3 shows the historical amount of the revenue adequacy surpluses and deficits in U.S. dollars. The accumulated revenue adequacy from 2007/08 to 2015/16 planning years is a deficit of 1.237 billion dollars with the highest cumulative deficit of 1.412 billion dollars occurring in planning year 2013/14.

To investigate the causes for the FTR revenue inadequacy issues, PJM has held three separate stakeholder processes to address FTR revenue adequacy since March 2011 as of October 15, 2015 [61].

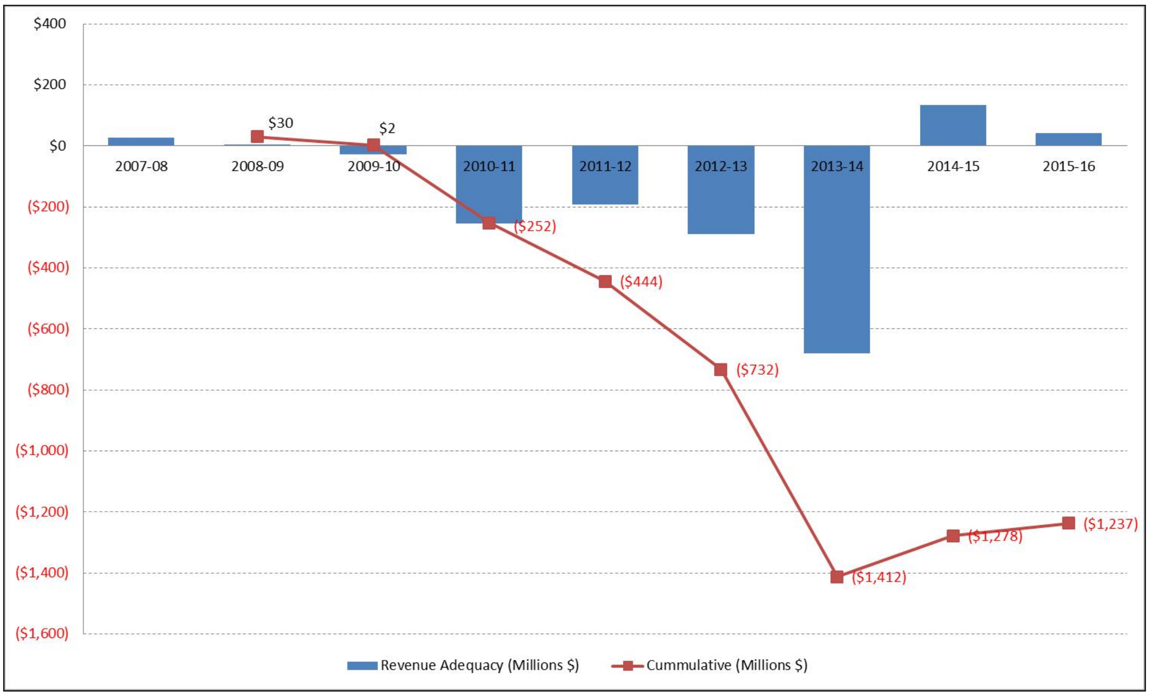


Figure 2.3: Historical PJM revenue adequacy [60]

2.2.2 Midcontinent Independent System Operator

Unlike PJM, the Midcontinent Independent System Operator (MISO) guarantees full payment for released FTRs; therefore the chart presented in Figure 2.4 reflects the FTR funding performance instead of the FTR payout percentage reported by PJM. Any shortfalls are collected from other market settlement sources to make up the difference. Notice that in each year since 2008 the funding performance has been less than one-hundred percent except for 2011 which had a surplus of 2.8%. Like PJM, MISO has a stakeholder process[4] to investigate and improve revenue adequacy.

[4]Financial Transmission Rights Working Group (FTRWG)

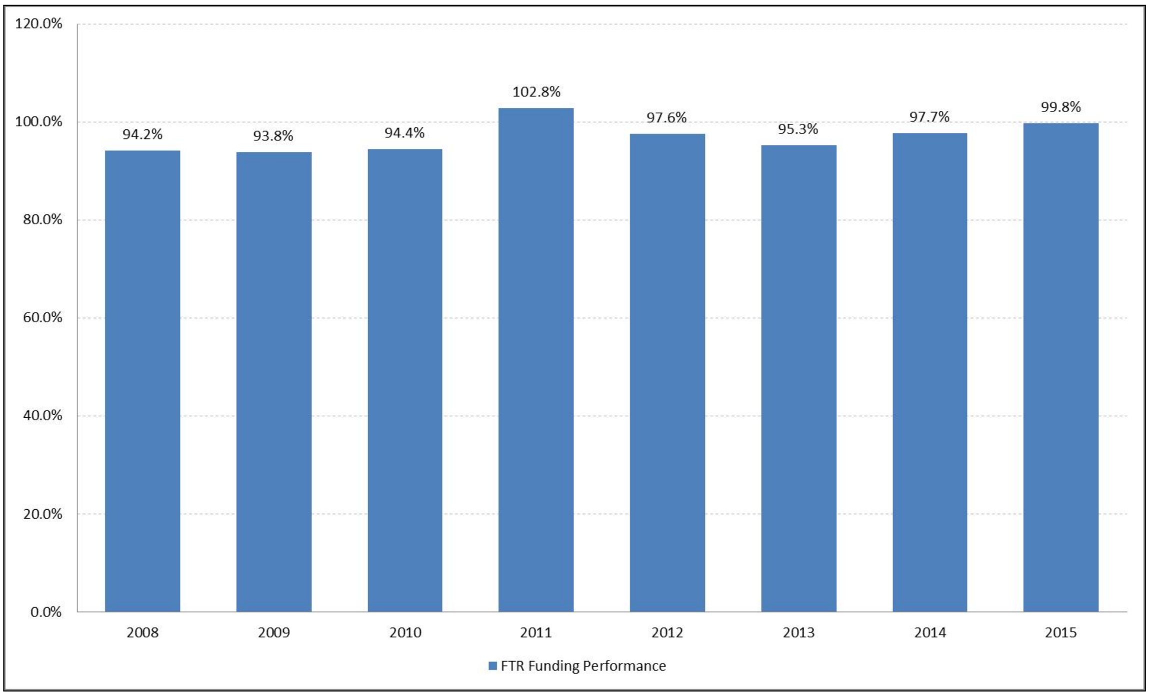


Figure 2.4: Historical MISO FTR funding performance percentage [62–66]

2.2.3 California Independent System Operator

The California Independent System Operator (CAISO), like MISO, guarantees full funding for their FTRs [67] which are called Congestion Revenue Rights (CRR). Figure 2.5 displays the annual shortfall in dollar amounts. In each of the seven years during the period from 2009 to 2015 since CRRs were first implemented the day-ahead congestion rents were not enough to fully fund the CRRs and the cumulative amount of inadequacy during this period amounts to 466 million dollars.

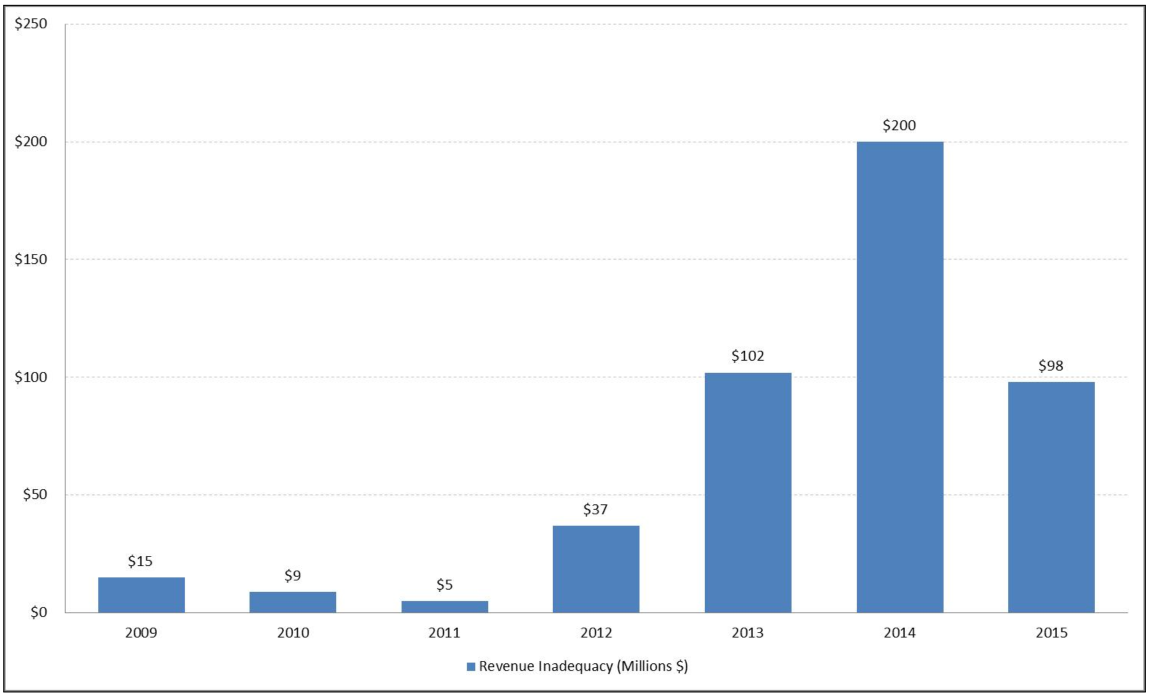


Figure 2.5: Historical CAISO CRR revenue inadequacy [68–70]

2.2.4 New York Independent System Operator

The New York Independent System Operator (NYISO) is another RTO that fully funds their FTR instruments called Transmission Congestion Contracts (TCC). They report revenue inadequacy as a TCC funding shortfall percentage. In this case, any surpluses and deficits are absorbed by the transmission companies in the NYISO region. The graph in Figure 2.6 indicates shortfalls in each year from 2009 to 2015 with an average shortfall, in percentage, of 13.1%. In 2012, NYISO implemented changes to their TCC action modeling assumptions that reduced the shortfalls in the subsequent years.

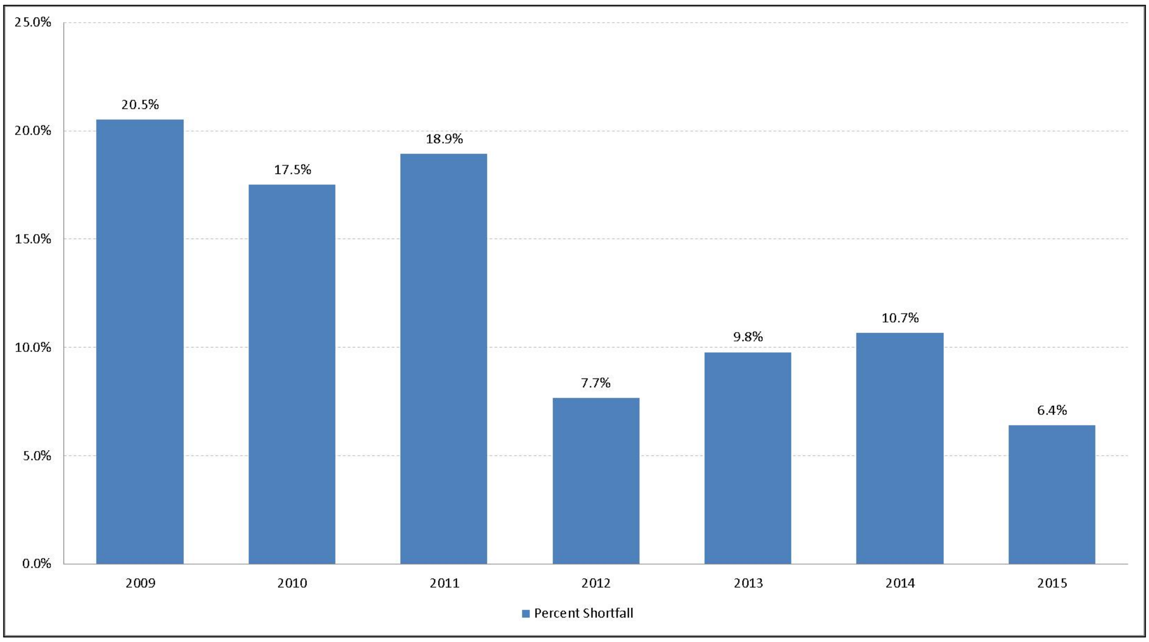


Figure 2.6: Historical NYISO TCC funding shortfall percentage [71–76]

2.2.5 New England Independent System Operator

Figure 2.7 shows the historical FTR funding performance in percentage for New England Independent System Operator (NEISO). From the period beginning 2006, the New England Independent System Operator (NEISO or ISONE) experienced few years of FTR underfunding. In fact, in several years during this period, they have experienced surpluses even though NEISO makes available up to 95% of the transmission capacity in their monthly auctions. Other markets make much less available, for example, in ERCOT it is a 10% reduction of all transmission system equipment capacities and in CAISO which varies every month typically is 15% or more (see Figure 2.11). However, there are a couple of reasons. The first reason is that New England ISO substantially reduces the ratings of their interfaces[5] between regions because the power transfer capability of the interfaces is difficult to calculate with certainty; therefore, they are very conservative in setting the interface limit. When any of these interfaces become congested, the amount of the congestion rents will be greater than the amount of FTRs allocated that creates a surplus which is used to pay any other constraints that are revenue inadequate. The second reason is due to the effect of recent transmission upgrades on their system that has substantially decreased congestion.

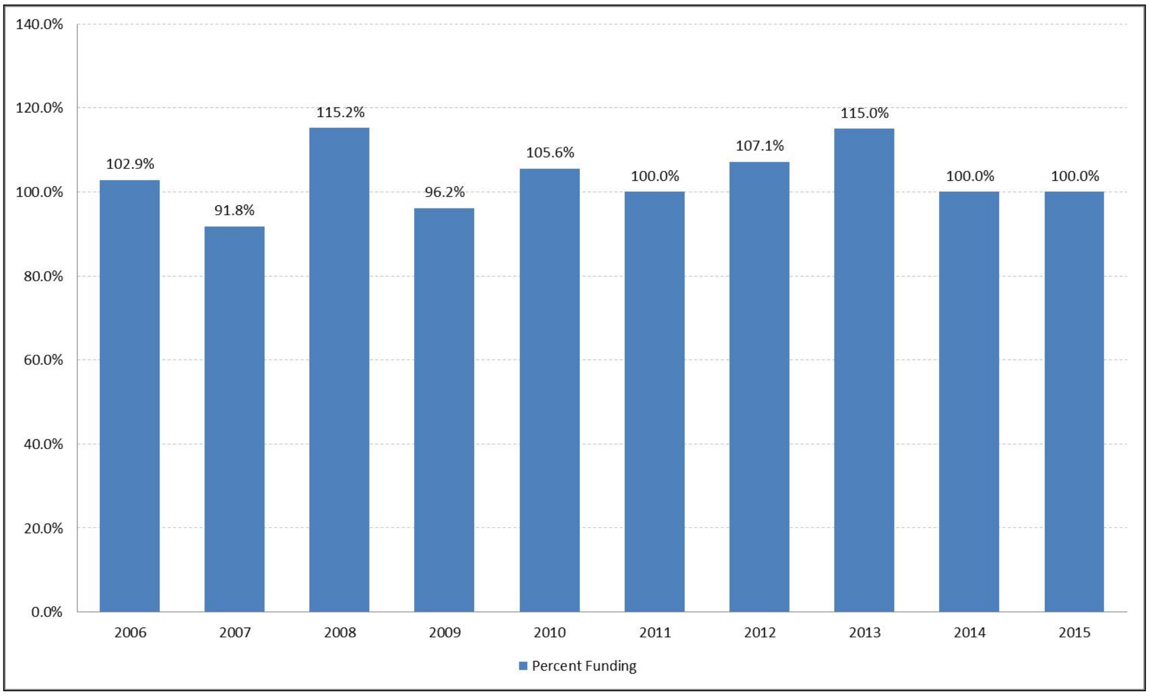


Figure 2.7: Historical NEISO FTR funding performance percentage [77–82]

[5]An interface is a grouping of transmission lines that limit the flow to or from a region for reliability concerns. *e.g.*, stability ratings

2.2.6 Electric Reliability Council of Texas

In the Electric Reliability Council of Texas (ERCOT), like in CAISO, FTRs are called Congestion Revenue Rights (CRR). ERCOT uses two methods to manage infeasible CRRs that incur revenue inadequacy. In the first method, ERCOT investigates which constraints are revenue inadequate and then discounts the CRRs that impact the revenue inadequate constraint in a prorated fashion [83]. In this case, only, the CRR holders that have CRRs that flow over the constraint are derated. ERCOT calls this process CRR deration. If the CRRs are still underfunded, ERCOT will make up the difference through a shortfall payment by all the CRR participants who have positive value CRRs. The stacked bars in Figure 2.8 displays the amount of monthly CRR deration and shortfall charges, and the line shows the CRR percentage payout during the period from December 2010 to July 2013. These values are displayed before applying the balancing account system. The monthly balancing account system is a financial repository that accumulates surplus congestion rents during each settlement period to subsidize revenue inadequate periods. The purpose of this account is to preserve the value of the CRRs. At the end of the month, any balance account surplus is credited to the load serving entities by load ratio share or deficit is charged accordingly using deration and shortfall charges. In 2014 after applying the monthly balancing account, the CRR funding percentage was 94% with $19 million in deration charges and $11 million in shortfall charges.[6]

[6]Note: ERCOT makes available 90% of the transmission capacity. The shortfall and deration charges would be greater if ERCOT released 100% of their system capacity.

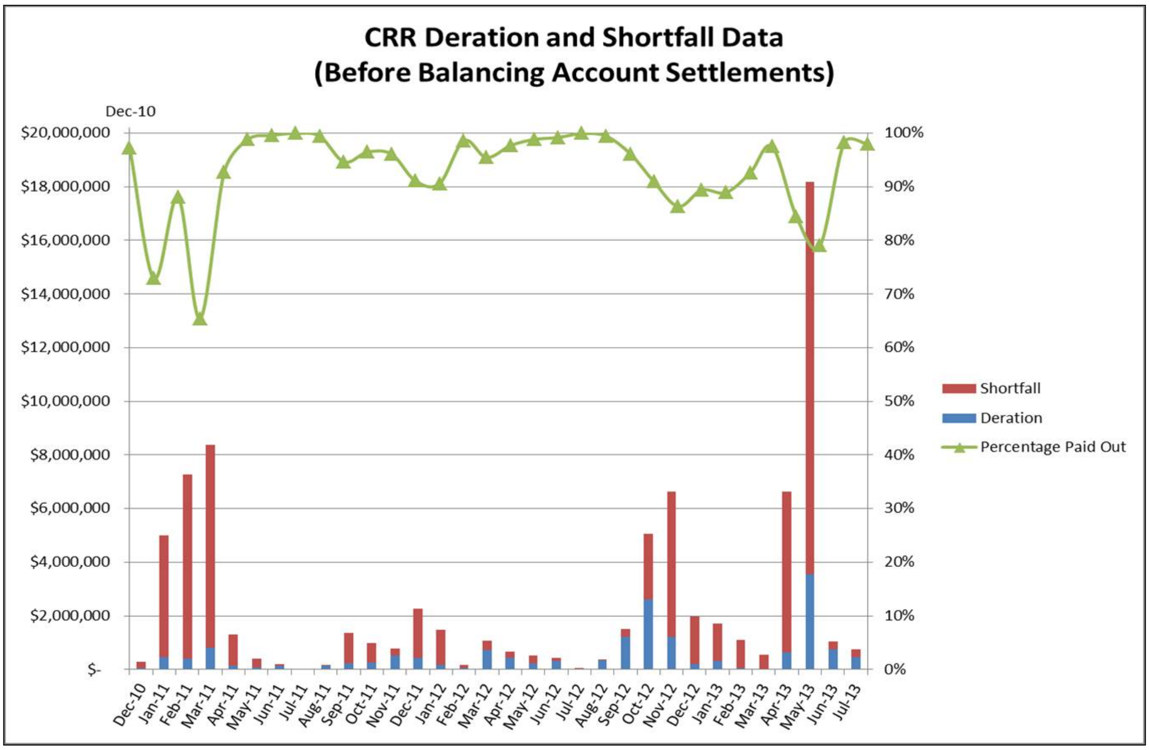


Figure 2.8: Historical ERCOT CRR deration and shortfalls [84]

2.2.7 Southwest Power Pool

The Southwest Power Pool (SPP) began their Integrated Marketplace in March 2014 offering FTR instruments called Transmission Congestion Rights (TCR). Figure 2.9 shows the TCR funding performance for the first two years of operations. In 2014, the funding performance was 85%, and in 2015 it was 86%. These percentages equate to 56 and 33 million dollars of shortfalls respectively. Like PJM, SPP manages the underfunding by prorating the TCR payments to the TCR holders.

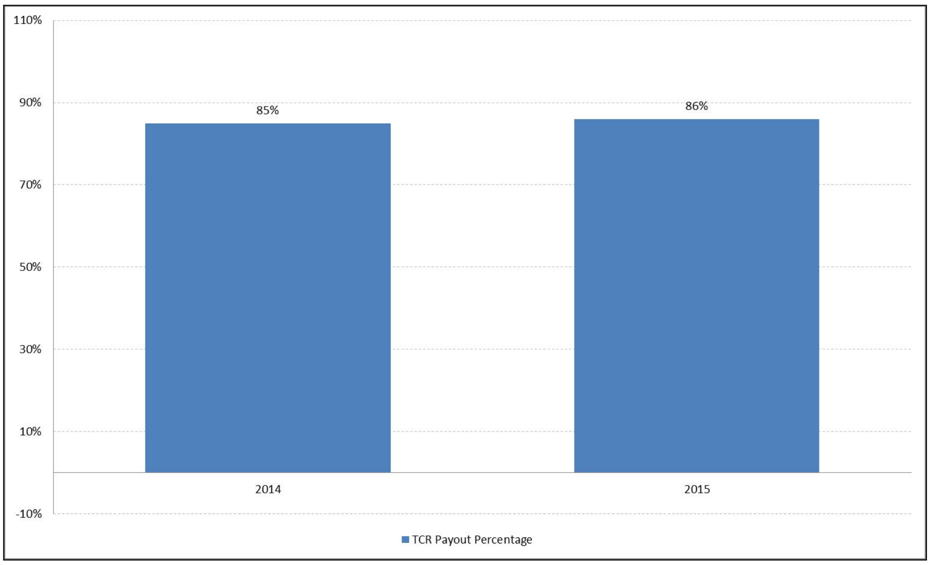


Figure 2.9: Historical SPP TCR funding performance percentage [85, 86]

2.2.8 Independent market monitors

As can be seen from the FTR funding charts in this section, historically, most RTOs experienced underfunding due to revenue inadequacy. In some RTOs, the underfunding was substantial. All RTOs monitor and report on the management of revenue adequacy, which is also one of the metrics used by independent market monitors to gauge the effectiveness of the market. Independent market monitors (IMM) are retained by RTOs to analyze the design and the functioning of the power market. IMMs typically provide periodic state of the market reports that contain analysis and information about FTR markets and revenue adequacy.

2.3 Causes of FTR underfunding and revenue inadequacy

Revenue inadequacy causes underfunding, however underfunding is not revenue inadequacy. This section begins by describing the difference between the two commonly used terms by RTOs to report the status of their revenue adequacy periodically. Once that is explained, the known causes of FTR revenue inadequacy and underfunding are presented.

2.3.1 Difference between revenue inadequacy and underfunding

Some RTOs describe FTR underfunding in association with revenue inadequacy, but the two terms have different meanings. In general, underfunding is a term RTOs use when revenue inadequacy occurs, but may also include insufficient funds from other sources. For example, this includes FTR auction revenues or congestion rents collected from the real-time market.[7] In a simple one-market system (as will be used in the examples in this dissertation) the term revenue inadequacy is the circumstance where insufficient congestion rents are collected to pay the FTR holders from the LMPs that are calculated during the real-time operation of the system. However, all

[7]Congestion associated with the real-time market is called balancing congestion as opposed to day-ahead congestion.

U.S. RTOs have adopted a two-market system in addition to the FTR market. One is called the real-time market, and the other is the day-ahead market.

The real-time market is the same as the one-market system where the LMPs are calculated to operate the system and reflect actual system conditions. The day-ahead market[8] is a financial market where no actual power is being produced or consumed and is not susceptible to random events that can cause price volatility during the actual operation of the power system. Market participants such as generators, operators, and load serving entities participate (either offer to sell power or bid to purchase power) in the day-ahead market to prevent financial exposure to real-time price volatility. As long as the transactions that cleared in the day-ahead market are physically delivered or consumed in the operating period (real-time), the market participants have no financial exposure to the potentially volatile real-time prices. However, if the market participants deviate from their physical obligations, then they must pay (or be paid) based on the real-time prices.

In some markets, (*e.g.*, PJM) FTRs are paid by congestion rents from both the day-ahead and real-time markets, and in other markets (*e.g.*, ERCOT), only from the day-ahead market. Day-ahead transactions can be thought of as shorter term FTRs with a period of one day. Like the FTR allocation process, the day-ahead market also uses an SFT to constrain the market transactions. This is an important point since the day-ahead market may be revenue adequate and have a surplus of

[8]As the name implies the day-ahead market occurs the day preceding the operating (real-time) day

congestion rents but be called underfunded because the real-time market may not produce enough congestion rents to pay day-ahead transactions. In other words, the real-time market may be revenue inadequate such that the total congestion rents collected in both the day-ahead and real-time markets cannot cover the payments to both the FTR holders and the day-ahead transactions.

Combining the day-ahead with the real-time settlements creates a situation of cross-subsidization where surpluses in one market settlement are used to fund shortfalls in other market settlements. Like the FTR market process, there are other related market financial instruments in RTOs that depend on transmission capacity for both their allocation and settlements based on the realization of congestion rents. Figure 2.10 displays a diagram depicting the energy market process.

Holders of physical transmission rights convert their rights to an instrument called Auction Revenue Right (ARR), which entitles the holder of the ARR to the FTR auction revenues. The ARR allocation process determines the feasibility of the submitted candidate physical transmission rights using an SFT process that limits the ARR allocation to the estimated future transmission system capacity using a simultaneous feasibility test similar to the FTR auction process. The holder of the ARRs can convert their ARRs into FTRs by a process called self-scheduling – the effect of this action is to trade the value from the FTR auction revenues for the day-ahead revenues for the path selected. However, if the ARR holder decides to keep their ARRs, the merchandising surplus (congestion rents) derived from the transmission system

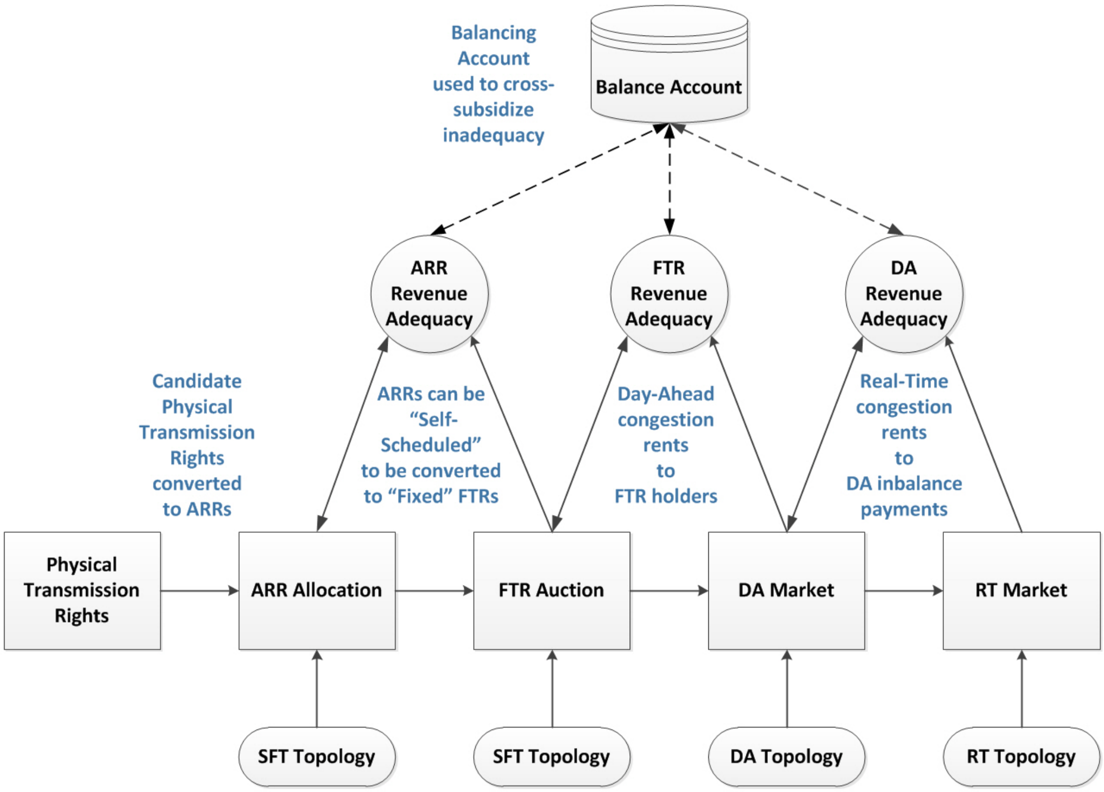


Figure 2.10: RTO market process

constraints used in the FTR auction will be used to pay the ARR holders. If there is less capacity in the FTR auction transmission model on the transmission constraints then there will not be enough merchandising surplus collected to pay the ARR holders fully. The same situation can occur between the day-ahead market and the real-time markets since the day-ahead market transmission configuration may not align with the real-time transmission configuration. This is displayed in Figure 2.10 where the ovals depict different transmission system SFT topologies for their respective market process and the circles represent the revenue adequacy condition that is managed by the RTO. The flat cylinder at the top of the diagram shows a settlement construct called a balancing account. The dashed lines indicate that the RTO may elect to cross-subsidize these market settlements.

Another method to manage FTR funding is temporal cross-subsidisation where surpluses that occur during one time period created by FTR under-allocation is put into the balance account to fund periods where FTRs are over-allocated. Lastly, constraint cross-subsidisation is where one constraint that is revenue inadequate is funded by another constraint in the same period that is more than revenue adequate.

Cross-subsidisation is an administrative method to deal with the underfunding caused by revenue inadequacy and as such does not address the cause of underfunding. Resolving the underfunding problem is not the primary focus of this research; however, it is necessary to distinguish it from revenue inadequacy. This distinction is important because some RTOs, for example, have combined different settlement systems, or as discussed, fund FTR revenue inadequacy from other sources. In all U.S. RTOs, FTRs are settled using the day-ahead LMPs, therefore according to Hogan [49], only day-ahead congestion rents should be used to determine FTR revenue adequacy.

2.3.2 Known causes of revenue inadequacy

Revenue inadequacy is an intricate issue with many causes, all of which are ultimately derived from over-allocating FTRs [21, 49]. The FTR allocation is bounded by a Simultaneous Feasibility Test (SFT) where the bids are modeled as power injections (source) into a bus or group of buses that flow through the transmission system model and withdrawn from a bus or group of buses (sink). Bids modeled in this fashion obey Kirchhoff's laws thus the flows on each transmission line can then be determined. All bids are considered simultaneously feasible when the flows on the lines are at or within the rating of the lines (and other transmission equipment). In theory, based on Hogan's revenue adequacy theorem [1,49], if the bids are simultaneously feasible, the system is revenue adequate. However, as Hogan points out in [49], this is not the case in practice due to real conditions. The causes that drive revenue inadequacy are separated below into three categories. The first category concerns FTR modeling, the second category pertains to transmission capacity uncertainty, and the third category is FTR release policy and market design.

2.3.2.1 Category 1: FTR modeling

FTR modeling concerns itself with the method, assumptions and software configurations by which FTRs are released. Most RTOs release FTRs through an allocation and auction process that solves an optimization problem with simultaneous feasibility test constraints. The modeling assumptions that may over-release FTRs are listed below.

- Input assumptions
    - Parallel flows: Parallel flows occur due to the physical characteristics of the transmission system where the flows from a neighboring interconnected system flow over the system of interest. It is standard practice to assume a

set of fixed flows from a neighboring system in the SFT and then if the estimated flows modeled are less than the ones during the settlement period, too many FTR are released thus potentially causing revenue inadequacy.

  - Phase Angle Regulator (PAR) settings: A PAR is a specialized transformer designed for controlling the real power flow in a network. Like parallel flows, PAR adjustments change line flows in the SFT which, if misestimated, can lead to revenue inadequacy [87].
  - Dynamic line ratings: Transmission line ratings are set based on static and very conservative engineering assumptions (*e.g.*, pertaining to ambient temperature or wind speed) for determining conductor heat dissipation. Dynamic line ratings, on the other hand, increase line ratings by using short-term forecast or actual measurements of localized ambient weather conditions around the conductor instead of the conservative engineering values. Revenue inadequacy can occur if the dynamic ratings used in the Day-ahead market are less than the estimated dynamic line ratings used for the FTR allocation.

- Missing constraints: The definition of a transmission line constraint consists of a monitored element and may include one or more contingency elements (see Section 6.3.8 for further explanation of monitored and contingency elements). An FTR over-allocation may occur if either the monitored element or the contingency element is not defined in the FTR allocation model. For example, many

RTOs use an abridged set of line constraints (called flowgates) instead of the set of all possible combinations of monitored lines and contingencies (m number of monitored elements multiplied by n number of contingencies) to reduce computational time in solving the FTR allocation model, DA and RT markets. This creates a situation where the flowgates used in the DA market may not have been modeled in the FTR allocation SFT thus releasing too many FTRs.

- Software or system error: FTR system data management or software flaws may cause incorrect allocation results.

- Human error: FTR modeling engineer can make errors like entering incorrect configuration values into the FTR model that can provide the wrong allocation.

- Modeling approach or method: The modeling approach constitutes the engineering modeling decisions that the FTR engineer develops to form the method used to run the allocation process. Below are two examples that may lead to FTR over-allocation.

  - SINTO: Modeling one topology in the FTR model to represent the transmission configurations during the auction period. The FTR over-allocation caused by SINTO is explained in Chapter 4.

  - Outage duration imposition rules: RTO practice of modeling transmission outages that have a duration greater than or equal to minimum duration period (see Table 3.1). In this case, outages with scheduled durations less than the minimum duration period are not modeled in the FTR allocation process. The excluded outages may lead to an over allocation of FTRs.

2.3.2.2 Category 2: Transmission capacity uncertainty

The second category encompasses situations where revenue inadequacy is caused by transmission capacity uncertainty. As previously mentioned in Section 2.1, transmission capacity differences between the FTR release process and the topology during the period the congestion rents are generated directly impact revenue adequacy. For example, if a transmission outage that reduces transmission capacity is not modeled in the FTR released process, it can cause an over-allocation of FTRs.[9] The situations listed below are circumstances that create differences in between the topology used to allocate FTR and the topologies used to collect the congestion rents that pay the FTR holders. The last item of this list is also the subject of this thesis – the over-allocation of FTRs due to the impact of Braess's paradox and SINTO.

- Forced outages and deratings that occur after the FTR are released that reduce capacity of the transmission system.
- Planned outages that are not included in the FTR auction because they are submitted to the RTO by the transmission company after the FTRs are released.
- The imposition of additional constraints on the grid to ensure electricity quality

[9]Historically, this situation is a major contributor to revenue inadequacy in most RTOs.

[88] or reliability, *e.g.*, voltage stability limit constraint implemented due to a forced generator outage after the FTRs are allocated.

- Optimal Transmission switching [89, 90] changes the configuration of the transmission system to minimize the generation dispatch cost, and may cause a misalignment between the topology in the FTR model and the DA and RT models.

- Impact of Braess's paradox and SINTO in the FTR release process when the scheduled transmission outages have a duration that is less than the auction period. This phenomenon is explained in Chapter 4.

2.3.2.3 Category 3: Allocation policy and market design

The third and final category is FTR allocation policy and market design. This category contains three examples where the policy and rules of the market design create the risk of revenue inadequacy.

- Policy awarding infeasible ARRs: PJM has a Tariff and Operating Agreement provision [61] that requires PJM to allocate a minimum amount of ARRs (Stage 1A in the Annual ARR allocation) for a 10-year period even if the ARRs are infeasible. The limits on the constraints caused by the infeasible ARRs in the ARR allocation SFT are increased in subsequent rounds of the ARR allocation and future FTR auctions for that period. As explained in Section 2.3.1, an ARR is a financial instrument that entitles the holder a share of the FTR auction revenues or day-ahead congestion rents if the ARRs are converted to FTRs through a process called self-scheduling.

- Policy adopting Long-term FTRs: In 2005, FERC sent out an invitation [91] to any interested party soliciting comments on establishing long-term transmission rights in LMP markets. Prior to this time, the longest FTR term in any RTO was one year. Market participants that desired longer-term ability to hedge their transactions initiated the inquiry. FERC, in the inquiry, directly noted the risk to revenue adequacy involved in adopting the policy by stating, "providing such long-term rights presents challenges. One such challenge is that to the extent that the RTO hands out transmission rights over multiple years but actual grid conditions are different than those anticipated, the RTO could collect insufficient congestion revenues to pay the FTR holders. Decisions must then be made regarding who will bear the revenue shortfall. As might be expected, the longer the instrument's term, the greater the probability that grid conditions will be different than forecast."

- Combining different market settlement accounting streams: Some markets combine different dispatch settlements together to determine FTR payments, *e.g.*, in PJM, combining day-ahead and real-time market accounting to determine FTR funding. As Hogan explains in [49], the FTRs may be revenue adequate if the accounting streams are separated so that only the congestion revenue from the day-ahead market is used to fund the FTRs. As was explained in Section 2.3.1, by doing so, revenue inadequacy due to circumstances when the congestion rents collected from the real-time market are insufficient to pay the day-ahead transactions is removed from the FTR settlements.

2.4 Applied approaches to manage the funding issues

This section presents the practical methods that RTO use or has considered managing underfunding. As explained in Section 2.3.1, underfunding and revenue inadequacy are different terms since underfunding may include shortfalls due to revenue inadequacy from other market settlements. FTR revenue inadequacy specifically pertains to an over-allocation of FTRs when the transmission capacity in the FTR model is greater than the transmission capacity during the day-ahead market dispatch. Managing FTR revenue adequacy is more of a practice than a science given that many of the applied methods to reduce capacity in the FTR release process are based on historical experience, engineering judgment or is broadly applied.

The methods listed below are used to manage revenue adequacy by regulating the FTR model transmission capacity.

- Global derate factors: Practice of uniformly reducing the capacity of all lines by some percentage. For example, the CAISO varies the percent derating on a monthly basis for their monthly CRR auction, see Figure 2.11 and ERCOT uses a fixed global derating of ten percent for their monthly CRR auction

- Derate selected lines: This is a more targeted method to reduce individual line ratings in the FTR allocation model based on line's historical revenue adequacy.

- Add unscheduled outages: Add unscheduled outages to the FTR model that the RTO FTR engineers believe would create significant revenue inadequacy if forced out.

- Reduce the limits of the line by prorating the limits by the duration of the outage over the outage period in cases where a scheduled transmission outage is not modeled in the FTR allocation model because the outage duration is less than the minimum duration rule.[10]

The methods listed below are approaches that RTOs use to manage underfunding that can be classified either: cross-subsidization, uplift payments or reducing FTR payments.

- Spatial cross-subsidization: Within the same period constraint that creates surpluses are used to fund constraints that are revenue inadequate.

[10] Note: that reducing limits may be overly conservative in cases where the outage exhibits Braess's paradox.

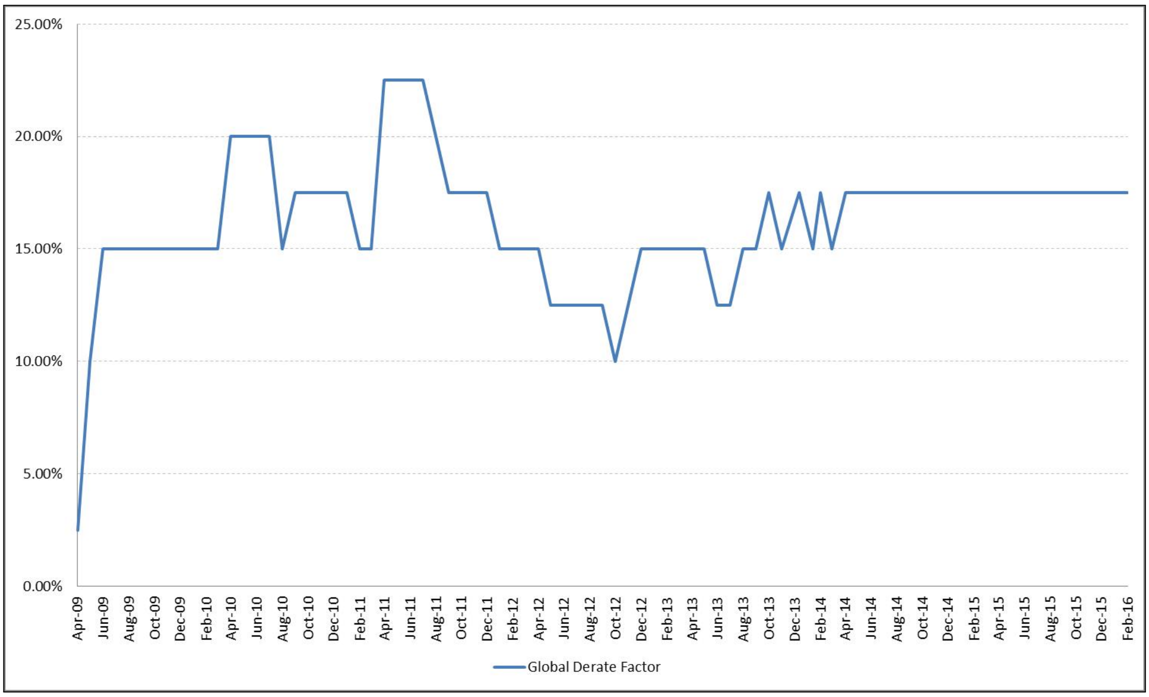


Figure 2.11: CAISO historical global derate factors [92]

- Temporal cross-subsidization: The use of a balance account nets surpluses from one settlement period to fund revenue inadequacy shortfalls in other periods, *e.g.*, monthly, rolling month, or annual [93].

- Market settlement cross-subsidization: Practice of combining different market settlements, *e.g.*, ARR auction revenues, RT market, marginal losses (not currently done in any market).

- Uplift payments: Recover revenue inadequacy shortfalls from either from the load (pro rata) or transmission companies [93].

- Derate FTR payments: RTO does not pay the FTR holders the full value of the FTR targeted payments and only distributes the congestion rents collected.

This derating is implemented in two ways. The first is accomplished by proportionally socializing the shortfall to the FTR holders so that FTRs are equally reduced by a percentage equal to the deficit divided by the total FTR target payments. The second way is to directly derate payments to the FTR holders whose FTR flow over constraints that are revenue inadequate, for example, this method is used in ERCOT see Figure 2.12.

Lastly, the two methods below provide examples of managing revenue inadequacy caused by market rules.

- Modify the market outage scheduling policy for transmission companies to have the transmission company submit planned transmission outages to the RTO so that the FTR model SFT can properly account for the outages.
- Modify market rule to prevent an RTO from mixing different market settlements (multi-settlement) that cause underfunding for the FTR holders so that the FTR holders do not subsidize deficits from other markets.

A goal of this research is to provide the RTO a new method that reduces FTR over-allocation due to Braess's paradox and SINTO by improving the FTR model SFT to reduce the degree of which the above ex-post facto or socialized techniques are applied. This research identifies a potential revenue inadequacy problem not previously considered by RTOs, and proposes new methods to manage that risk.

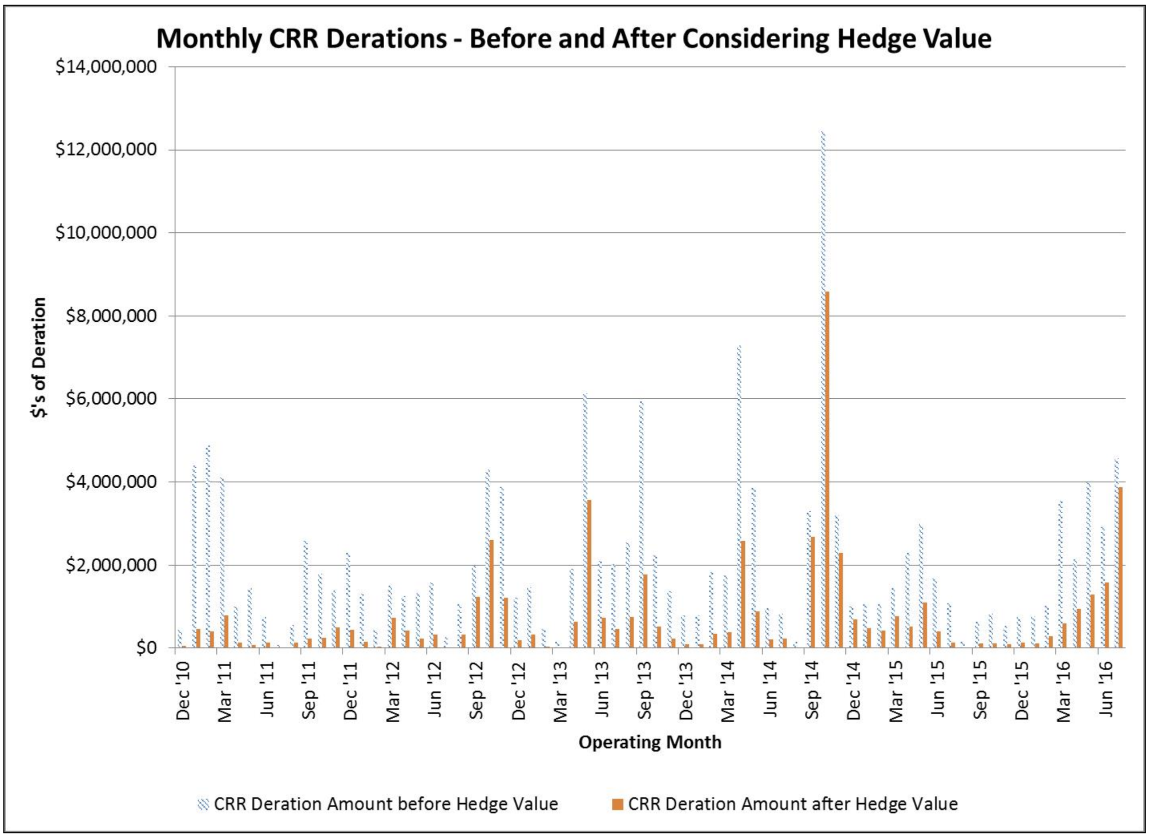


Figure 2.12: ERCOT historical CRR deratings [94]

2.5 Literature review: Theory of FTRs and revenue adequacy

This section complements the preceding sections of this chapter that provide an explanation of the causes diagnosed and practical solutions implemented by RTOs based on their actual experiences managing FTR markets. The theoretical work involving financial transmission rights encompasses a broad spectrum of topics including issues of market power, the incentive for transmission investments, FTR valuation, game theory simulations, FTR implementation experience, FTR formulation functional enhancements, and algorithmic optimization improvements. A summary compilation of references covering these FTR topics is given in [95, 96]. However, the central subject of this thesis is in identifying, investigating and solving a particular FTR issue that induces revenue inadequacy; therefore, this section primarily covers the relevant literature underpinning the development of financial transmission rights and the subject of revenue adequacy. In Section 2.5.1, the first objective is to review the relevant academic research on the development of FTRs and other congestion management products, emphasize the need for revenue adequacy in order to have successful FTR implementation, and the important role of the SFT in attaining revenue adequacy. The second objective is to present the research about the theoretical causes of and solutions to revenue inadequacy and is presented in Sections 2.5.2 and 2.5.3 respectively.

2.5.1 Literature pertaining to FTR design and development

In their 1982 seminal paper [4], Caramanis et al. laid the conceptual framework for electricity prices that accounts for the varying time and space nature of electricity operating costs – known today as locational marginal price (LMP). This concept was expanded comprehensively into the notional framework of an "energy marketplace" by Schweppe et al. in their 1988 book [97]. Leveraging this pricing mechanism, Hogan, in [98] proposed an alternative (called a “contract network”) to the then current physical firm transmission rights, which were specified in terms of “contract path” or “interface transfer capabilities.”

Physical transmission rights, specified in terms of contract paths, disregards important physical characteristics of power systems [99]. For example, it assumes that power transfers (due to power sales) follow the shortest path from generator to the delivery area where the load is located without impacting other transmission neighboring systems. However, in an actual system, power flows (for the desired power transfer) take parallel paths with flows on each path being inversely proportional to their impedances. As a result, parallel flows can cause overload issues in neighboring systems during the operating period. In path-based systems, such congestion is managed inefficiently through a process called Transmission Loading Relief (TLR) [11], where transactions are curtailed based on the firmness of transmission service as previously discussed in Section 2.1.

Physical transmission rights, are usually specified in terms of interface transfer capabilities. Their problem is that the transmission service providers use rough estimates of transfer capability between control areas to manage power transactions. Figure 2.13 displays a portion of the 2004 NERC control area map used by power traders and marketers to trade power between the control area regions. The circles represent control areas and the lines connecting the circles are paths representing all the transmission tie lines between control areas. For each path, the transmission service provider estimates the transfer capacity limit to cap power transactions (trades). In addition, physical transmission rights require an alignment between the generation

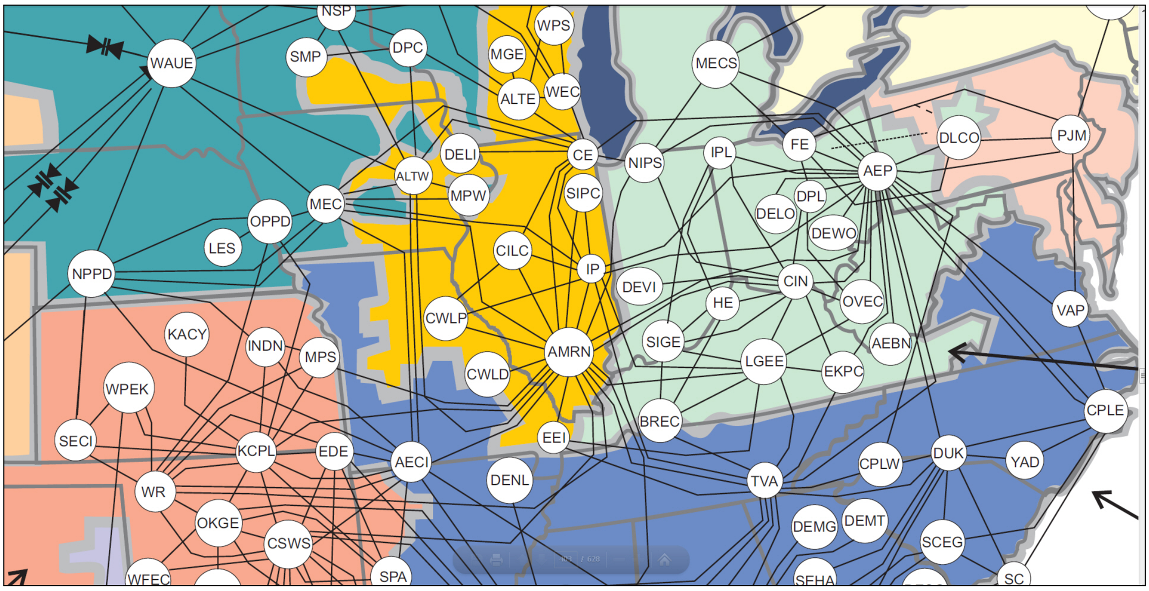


Figure 2.13: 2004 partial Control Area map [100]

dispatch and use of the transmission system (through a process called "tagging"). For example, a trader has to coordinate the power trade, acquire transmission service and schedule the transmission service by tagging it. This method to facilitate power trading requires a significant amount of work and requires the transmission service provider to recalculate the available transmission capacity of the transmission system continually.

In contrast, the transmission rights associated with a Hogan's "contract network," called Transmission Congestion Contracts (TCC), adhere to Kirchhoff's laws. TCCs preserve the value of the physical transmission rights,[11] and exploits the prior work of

[11]This assumes the long-term capacity right holder is indifferent between delivering the power at a distant node or receiving the compensation from congestion rents that reflect the opportunity cost

Schweppe et al. on efficient short-term spot pricing (LMP), which incentivize efficient dispatch of the generation. Contract network associated rights that use "congestion payments as a rental fee for the utilization of the capacity rights [98]" later became known as financial transmission rights. Hogan deduced a centralized market design structure where the transmission grid operator administers and manages the FTR process.

Hogan concluded that it is in the grid operator's best interest (since the grid operator would control the FTR process) to determine if the congestion revenue is sufficient to cover the payments to the FTR (capacity right) holders. For a contract network to be successful, it is vital that revenue adequacy is achieved, so Hogan in [1] mathematically provides proof that FTRs are revenue adequacy under various conditions. To this end, Hogan explains that for the DC load flow approximation there is exact revenue adequacy for congestion payments if the flows induced by the set of rights would be feasible. Hogan's FTR is preceded with the term "point-to-point" because it is calculated from the difference in LMP prices between any two settlement points that define its path.[12]

In [11], Chao et al., proposed a different type of transmission right called a flow-based transmission right or flowgate right. A flowgate right (FGR) is a financial right that is defined by a network link[13] (line, transformer, set of lines) instead of

in the network [98].

[12]In this thesis, the "point-to-point" designation may be dropped thus any reference to FTR means point-to-point FTR.

[13]Oren, in [101], referred to FGRs as Link Based Rights (LBR)

bus-to-bus (point-to-point) and is settled using the shadow price of the link if the link becomes congested instead of the LMP difference between two points (buses).

The relationship between FTRs and FGRs is analogous to the relationship between the LMP difference between two buses and the shadow prices on constrained lines in a transmission system. However, before continuing further with the analogy, power transfer distribution factors[14] (PTDF) are defined.

In a linearized DC power-flow model, the sensitivity for a power transfer (from one bus to another bus) on the flow on a transmission line in the system can be expressed by a constant number called a power transfer distribution factor, which has a value between +1 and -1. The PTDF equation shown below is from [102].

$$A_{ij\ell}^{\text{PTDF}} = \frac{\Delta f_\ell}{\Delta P_{ij}}$$

where

ℓ is the line index

i, j are the bus indexes where power is injected and taken out, respectively

Δf_ℓ change in MW power flow on line ℓ when a power transfer of ΔP_{ij} is made between buses i and j

ΔP_{ij} is the power transfer from bus i to bus j.

[14]The derivation for a Power Transfer Distribution Factor can be found in [102] Appendix 7B on page 336.

For example, a one megawatt injection at bus i that is withdrawn at bus j with a PTDF value of $A_{ij\ell}^{\text{PTDF}} = 0.12$ on line ℓ would increase the flow on the line ℓ by 0.12 megawatts.

Now with an understanding of the PTDF, the analogy between FTRs and FGRs to LMP and shadow prices is presented below. If resistance losses are disregarded in the dispatch optimization (*e.g.*, like it is presently in the ERCOT market), the LMP difference between two buses can be expressed in terms of transmission constraints as shown below, which shows the relationship between FTRs and FGRs.

$$\pi_{ij}^{\text{MCC}} = \pi_j^{\text{LMP}} - \pi_i^{\text{LMP}} = \sum_{\ell \in \mathcal{L}} A_{ij\ell}^{\text{PTDF}} \times \pi_\ell^{\text{Shadow}}$$

Where

ℓ is the line index in the set of lines $\mathcal{L}$

i, j are the bus indexes where power is injected and taken out, respectively

π_{ij}^{MCC} is the marginal congestion component from buses i to j [$/MWh]

π_i^{LMP} is the locational marginal cost at bus i [$/MWh]

π_i^{Shadow} is the shadow price on the line ℓ [$/MWh]

$A_{ij\ell}^{\text{PTDF}}$ is the power transfer distribution factor on line ℓ due to changes in power transfer from bus i to j.

From the relationship, the difference in LMPs between buses is equal to the sum of the shadow price π^{Shadow} multiplied by its corresponding sensitivity factor (A^{PTDF}) on all lines. Correspondingly, the equation below describes the relationship between the value of an FTR to FGRs[15] where q_{ij}^{FTR} is the financial transmission rights quantity [MWh] from bus i to bus j and q_{ℓ}^{FGR} is the financial flowgate rights [MWh] on the lines $\ell \in \mathcal{L}$.

$$q_{ij}^{\text{FTR}} = \sum_{\ell \in \mathcal{L}} A_{ij\ell}^{\text{PTDF}} \times q_{\ell}^{\text{FGR}}$$

In [11], Chao et al. describes an FTR as a "portfolio of flowgate rights" since an FTR has a unique correspondence with flowgates. Conversely, in the reverse arrangement, the unique correspondence between FTRs and FGRs is not maintained when decomposing an FGR into a set of FTRs. There may be a multitude of point-to-point FTR combinations that are equivalent to the same FGR quantity.[16]

Although there is a direct relationship between FTRs and FGRs, according to [11, 103], one of the main advantages of the flowgate right is that the FGR allocation does not require a simultaneous feasibility test since the feasible quantity of FGRs on each link (*e.g.*, a line) is not sensitive to network topology changes or is independent of power flow patterns. However, in [104], Hogan argues that the transmission system is operated under n-1 contingencies,[17] thus the quantity of FGRs that could be allocated

[15]The FGR is defined as a single line in this case.

[16]The exception is in the case of a radial system that has a 1:1 correspondence.

[17]An n-1 contingency is an NERC reliability criterion where the power system must be operated such that the flows on each line in the transmission system must stay within the operating limit for the loss of any system component (*e.g.*, transmission line). The implication of this criterion is that

changes for every contingency [103, 105] because the flows would be different under each contingency. Therefore, the FGR (like the FTR) is dependent on topology changes and power flow patterns.

Another claimed advantage posited by advocates for FGRs is that their implementation would be simpler than point-to-point FTRs and as such would better facilitate the power market. The assertion is that there are many more possible point-to-point FTRs combinations than there are FGRs since the number of possible FGRs would be limited by the number of connected links (transmission lines) on the network. However, due to the NERC contingency criteria discussed above, each FGR would be a combination of a monitored line and a contingency pair, and since there are n-1 contingencies, there would also be a great number of possible FGR combinations [105].

After FGRs had been first proposed by Chao et al., a large debate ensued as to which financial instrument was better for the market, for examples, see [11, 103–108]. Others proposed market designs that accommodate both types. In [109], Tabors proposed a hybrid model that synthesizes both FTRs and FGRs to facilitate the creation of a forward market and a stable delivery system. O'Neill et al., in [18, 110], proposes a flexible hybrid energy and transmission market design structure that incorporates both FTRs and FGRs as well as energy trades through a series of jointly optimized energy and transmission right auctions. Several RTOs have designed

each line (or system component) must allow for the redistribution of flow due to the contingency of another system component thus the line cannot be fully loaded to its limit. The n-1 designation refers to the number of system components (n) except the one removed from service for analysis (n-1).

auction and allocation systems that offer both FTRs and FGRs. However, FTRs are the most popular financial transmission right among market participants.

While FTRs and FGRs emerged as the most prominent, other types of rights were also proposed, including the Contingent Transmission Right and the Loss hedging financial transmission right. O'Neill et al. proposed the Contingency Transmission Right [8]. A Contingency Transmission Right is a financial right that contains multiple path designations (multiple sources and sinks). The concept is analogous to network transmission service associated with physical transmission rights markets. With network transmission service, the holder of the right has the option to schedule transmission service from generators (sources) they designated as a designated network resource to one or more loads (sinks) within the control area. Network transmission service, unlike point-to-point transmission service, gives the holder of that right, the right to select which generators they prefer to run. For example, in the case when a generation outage happens. Likewise, a Contingent Revenue Right provides similar flexibility in that the holder of the financial right would have the option to hedge any source and sink combinations pertaining to the right thus allowing "for generation portfolio choice and also providing a hedge against generation outages." Although [8] claims that Contingent Revenue Rights are revenue adequate via examples, no formal mathematical proof is provided. Currently, no RTO offers Contingent Revenue Rights.

In addition to optimizing the value of demand bids minus the cost of resource offers to minimize electricity cost, almost all RTOs[18] also reduce the cost due to transmission losses – where generators that decrease losses are rewarded by formulaically adjusting their bids and penalizes generators that increase losses likewise. The implementation of minimizing losses is referred to as marginal loss pricing. In marginal loss pricing, the LMP is decomposed to a marginal energy component (MEC), marginal congestion component (MCC) and a marginal loss (MLC) component. The energy component is the same for all pricing nodes in the system. The congestion component is as the name implies dependent on congestion in the system thus may be different for different pricing nodes. The marginal loss component also varies by location, therefore, may create a price difference between a generator bus and load bus even if there is no congestion. The FTR auction (as opposed to the Day-ahead and real-time markets [111]) uses a linear power flow model thus does not solve for power losses which is a quadratic equation ($P_{Loss} = I^2 \times R$) therefore FTRs are allocated without accounting for losses. In RTOs that implement marginal loss pricing, FTRs provide a hedge for congestion price differences ($\pi_{ij}^{\text{MCC}} = \pi_j^{\text{LMP}} - \pi_i^{\text{LMP}}$) but not for marginal loss component price differences. In [112], Harvey and Hogan extend the FTR concept to provide hedges for both losses and congestion between two buses. In this paper, Harvey and Hogan summarize the advantages and disadvantages of five different market designs that account for transmission losses and FTRs - two of which are prevalent today: marginal loss pricing and average loss pricing.

[18]Except for ERCOT

Although most discussions in the literature center on FTRs and FGRs, RTOs have designed systems that accommodate both types. However, market participants prefer FTRs. According to [93], FGRs are not adopted because "energy traders prefer FTRs that are more suitable for hedging point to point congestion risk." For example, to provide a simple hedge between two points using FGRs, an energy trader would have to determine what lines (links) would be constrained and under what contingencies (if the FGR are defined uniquely as a monitored element and contingency pair) and the quantity of the capacity to bid (since only a portion of the flows from the hedging transaction would flow on the constraint) to assemble the hedge. Whereas it is much easier with an FTR – the trader only has to designate the source and sink points, the bid price and the quantity desired.

Despite their differences, both FTRs and FGRs have the advantage (as opposed to physical transmission rights schemes), of being unbundled into transmission rights that enable the efficient dispatch gained from Schweppe's spot market to be realized. However, the successful implementation of both depend on collecting enough congestion rents to pay the rights holders. Therefore, the simultaneous feasibility test is critical to preventing revenue inadequacy due to the over-allocation of FTRs and FGRs.

In the next section, power flow problem characteristics are examined in the context of the dispatch optimization problems to understand how they impact revenue adequacy.

2.5.2 Literature on revenue adequacy

> "A central issue in the provision of FTRs by an ISO is revenue adequacy [44]."

Section 2.3.2 details many of the possible causes of revenue inadequacy that RTOs have experienced, which are categorized as either modeling assumptions, transmission outage uncertainty, and policy and design. Also, Section 2.3.2 describes the practical methods that RTO use to manage underfunding and revenue inadequacy. The simultaneous feasibility test accompanying the FTR allocation ensures revenue adequacy when the transmission configurations used by the FTR allocation model and the day-ahead market model are consistent. This concept is also known as the Revenue Adequacy Theorem. Various versions of the Revenue Adequacy Theorem are provided in the literature but have the same meaning. For example, in [113], the theorem is stated as: "the TCC[19] revenue from a consolidated set of feasible contracts under the optimal dispatch is no greater than the merchandising surplus." And in [114] the definition of Revenue Adequacy Theorem is given as: "when the extant FTR contracts are simultaneously feasible, the rentals earned by the ISO are sufficient to fund the coupon payments to the FTR holders." Theoretically, however, other conditions are necessary for achieving revenue adequacy. Presented here is the research that proves the Revenue Adequacy Theorem and under what conditions.

In his seminal work on a Contract Network, Hogan in [48], offers the first mathematical proof where an FTR allocation based on an auction using a simultaneous

[19]TCC stands for Transmission Congestion Contract.

feasibility test with a linear DC load flow approximation achieves revenue adequacy. In this case, assumptions are made to simplify the nonlinear aspects of an AC system, for example, ignoring power system characteristics such as transmission losses, voltage constraints, and reactive power flows. Following this initial work, Hogan and others, in subsequent work, extend the revenue adequacy theorem by proving it holds under other conditions, for other products types (*e.g.*, flowgate rights, options) or modeling methods (*e.g.*, convexification).

In [113], Bushnell and Stoft prove that the using a Feasible Lossy Dispatch with a relaxed energy balance constraint (inequality rather than equality) is convex when using the DC load flow with quadratic losses approximation. In [115], Hogan and Pope prove that FTR[20] Options for a DC approximation under contingencies are revenue adequate. There are two types of FTRs – Obligations and options.[21] FTRs are directionally defined by a path from one point to another. For both FTR Obligations and Options, if the direction of congestion flow is in the same direction as the FTR, then the holder receives a payment equal to the price difference between the two points. However, if congestion flow is in the opposite direction, the FTR Obligation holder is charged the difference between the two points whereas there will be no charge to the FTR Option holder. In [46], a practical test is conducted using auction software to determine the effect of introducing FTR Options to the New England ISO

[20] In this memorandum, Hogan and Pope refer to Transmission Congestion Contracts (TCC) instead of FTR because it is written to the NYISO Market Structures Working Group. In the NYISO, an FTR is called a TCC.

[21] Flowgate rights can also be of Obligation or Option type.

market. The test of six scenarios concluded that it appears evident from this revenue inadequacy test that the introduction of Option FTRs does not have a negative effect on the Congestion Revenue Fund, and in fact had a positive impact.

A Joint Energy and Transmission Rights Auction model proposed in [18] proved revenue adequacy for both FTR and FGR of both the Obligation and Options types for a linear DC model. In [110], this condition is expanded to include nonlinear transmission constraints that define a convex feasible region. In [1], Hogan comprehensively extends his previous work proving revenue adequacy for various combinations of FTR auctions with different power flow approximations (AC, DC, contingencies, and losses) and different financial rights products: Balanced and unbalanced bids, FTR Obligation and Options, FGR Obligations and Options.

The steady state characteristics of the electrical system, generator operating constraints, load characteristics and generator cost (bid) functions define the feasible space of a market dispatch optimization problem (or optimal power flow problem, OPF). The shape of the feasible space is an important criterion to solving an optimization problem. If the feasible space is convex[22] and the objective function is either maximizing a concave function or minimizing a convex function, then the solution is a global optimum solution.[23]

[22] A convex set is a set where a straight line segment connecting any two points within the set will not contain points on the line that is not in that set.

[23] If the function is separable in all variables, then a concave function has nonpositive second derivatives, and a convex function has nonnegative second derivatives. However, if the function is not separable Hessian conditions are positive semidefinite for convexity and negative semidefinite for concavity. [116]

Convexity is important for allocating FTRs because the FTRs should be feasible in the dispatch problem, or stated differently, the feasible region representing the implied simultaneous flows from the FTR allocation must be within the feasible region for the feasible optimal dispatch flows. If not, revenue adequacy can occur. In [117], Philpott and Pritchard prove for a convex optimization framework (where the transmission constraints are convex) that the SFT ensures revenue adequacy and presents two cases that do not satisfy the property, where either the network is affected by outages or has negative nodal prices. Also, [117] shows via example that in the nonconvex case you might get revenue inadequacy. On the other hand, Lesieutre and Hiskens, in [51], prove in general that the feasible power injections that satisfy the AC power flow equations are nonconvex and further demonstrates via example that the SFT does not ensure revenue adequacy. Also, in that case, Lesieutre and Hiskens suggest that policies should be adopted to accommodate revenue inadequacy since it cannot be theoretically achieved by the SFT.

The revenue adequacy theorem [48] depends on the convexity of the optimization problem where the convexity of the decision variables and the constraint functions form the feasible region. Since the power flow equations are nonlinear and nonconvex in the AC case, the revenue adequacy theorem may not hold under those assumed conditions. In practice, it suffices because all RTOs presently use a linear DC load flow with linear transmission constraints for both the day-ahead and FTR allocation models [118].

2.5.3 Literature on revenue adequacy solutions

In the previous section, the research shows that revenue adequacy is not theoretically achievable using the SFT due to the nonconvex nature of the power system equations. Also, that section provides guidance into the limitations of the revenue adequacy theorem in real markets even in the situation where the system topology in the FTR allocation and day-ahead market are the same. Therefore, methods to manage revenue adequacy or make up the shortfall are necessary and desirable in practice. Section 2.4 presented the various applied approaches used by RTOs to manage revenue adequacy and underfunding. The present section covers the literature concerning four schemes to reduce revenue inadequacy or underfunding. The first involves virtually expanding a transmission capacity in the FTR allocation by short selling FTRs. The second introduces a method of directly assigning the revenue inadequacy or surplus to transmission companies that change their network configuration from what they provided during the FTR allocation. The last two proposals use similar transmission switching techniques. One approach addresses revenue adequacy by ensuring the dispatch optimization produces a revenue inadequate solution and the other does so by improving the SFT in the FTR allocation process.

First, in [119], Oren and Hedman propose a virtual line capacity increase that expands the FTR auction feasible region (creating more capacity to sell FTRs) through a financial Flowgate Right (FGR) short position. In essence, an entity wishing to create the virtual line capacity would sell an FGR into the FTR auction so that they could receive the auction revenues generated from the additional line capacity the FGR creates. This would, in fact, create a short position where the entity that sold the FGR would be liable to cover the FTR payments for the additional FTRs allocated by the FGR sold. Any entity could sell FGRs; however, Oren and Hedman suggest that the transmission owner is the entity ideally suited since it provides the owner incentive for incremental improvements and maintenance. Financially, the entity interested in taking a short position is speculating that the payment received from selling an FGR is greater than the loss if it becomes congested.

Like the prior proposal, the next proposal associates the revenue inadequacy solution to the transmission owners. In [120], Rudkevich et al. propose a mechanism to directly assign the resulting revenue inadequacy shortfall to the transmission owners that deviate from the network topology they provided for the FTR allocation. The premise behind the paper is that the entity responsible for changes in the transmission system has the financial responsibility for the topology changes they make and the objective is to preserve the value of FTRs by ensuring they are fully funded. Rudkevich et al. propose a new financial instrument called the Transmission Reconfiguration Right (TRR). The TRR creates "transaction batches" using power injections and withdrawals that replicate the market network as promised capability in the FTR auction model then it uses the day-ahead market results to determine the economic value of the TRR. Subsequently, the TRR is then assigned to the transmission owner. Lastly, Rudkevech et al. amended the revenue adequacy theorem so that revenue adequacy is achieved by combinations of FTRs and TRRs.

The prior two papers aim to reduce underfunding by reassigning the revenue inadequacy liability to either an entity speculating to make a profit or one that has direct control of the transmission grid. The following two proposals use topology control formulation techniques to reduce revenue inadequacy.

Fisher et al. in [14] proposed an optimal transmission switching dispatch that economically dispatches generation using transmission switching. This work is succeeded and expanded by [121–128]. The impact of the optimal transmission switching upon revenue adequacy of FTRs is explained in [15, 90]. Fundamentally, the optimal transmission switching dispatch may change the operating period topology relative to the one used in the FTR model and creates a potential revenue inadequacy issue. This issue led to the following proposal to prevent the revenue inadequacy. In [89], Hedman et al. propose a modified optimal transmission dispatch formulation that constrains the topology configuration to be revenue adequate or to be a surplus based on previously allocated FTRs. The main drawback to this method is that it restricts the potential benefit gained from optimal transmission switching.

Lastly, in [129], Rangarajan and Wang offer an improved SFT formulation that is capable of analyzing constraints from multiple transmission configurations in the FTR auction. The formulation uses a transmission switching method to model expected transmission switching outages (if using optimal transmission switching dispatch), transmission maintenance outages, and contingencies. Also, the formulation uses a

Benders' decomposition technique that is formed into a master and sub-problem. The master problem is similar to FTR auction formulation that maximizes the economic value of the FTR bids that is subject to the transmission system constraints. However, in this formulation, a binary variable controls whether a line is open or close to model the first set of topology configurations in the SFT. The auction solves in an iterative fashion that begins by solving the master problem for an initial set of "sanctioned" bids. The process then passes the sanctioned bids to the sub-problem where they are further tested to determine if they are feasible in the second set of topologies. The sub-problem is configured to send a pass/fail indication (another set of binary variables) to the master problem if the sanctioned set of bids are not feasible. If not feasible, then feasible cuts are passed to the master problem to begin another iteration until the Benders' upper and lower bounds converge, and reaches an optimal solution. Both the master and sub-problem are capable of modeling outages however the authors recommend that expected topologies (*e.g.*, based on maintenance outages) be put into the master problem and less probable topologies (*e.g.*, based on short duration outages) be put in the sub-problem. The advantage of this improved SFT formulation is that independent sub-problems can be solved by parallel processing to reduce the overall computational time.

This thesis adds the literature described in this section by identifying how Braess's paradox and SINTO impact revenue adequacy and proposes solutions that can reduce its effects.

Chapter 3

Theoretical Background

3.1 Introduction

The goal of this chapter is to build an understanding of locational marginal prices (LMPs), Braess's paradox, SINTO, and the dispatch and FTR auction formulations in order to demonstrate in the next chapter how Braess's paradox and SINTO in FTR auctions can cause revenue inadequacy. Section 3.2 begins by explaining LMP using a simple three-bus system to understand some important characteristics of LMP and flow in transmission systems. This is followed by an expository on Braess's paradox from its discovery in transportation systems to its identification in power systems. Braess's paradox was applied to electricity markets by Blumsack [37] and it yields a perverse outcome. In short, Braess's paradox indicates that in certain instances, the addition of transmission capacity in the form of another line can reduce the overall capacity of the system. Then two circuits that exhibit Braess's paradox are introduced. The first is a well-known circuit called the Wheatstone bridge. The second is a parallel two-circuit system with one circuit having relatively higher admittance and lower capacity compared to the other (parallel high admittance low capacity or PHALC circuit). These circuits are combined in Chapter 4 to illustrate how Braess's paradox and SINTO in FTR auctions can lead to revenue inadequacy. Section 3.4 explains how RTO/ISOs use SINTO in FTR auctions and it hypothesizes how the practice originated. This is followed in Section 3.5 with a description of the optimization models used in Chapter 4. The first is an optimal power flow (OPF) formulation considering transmission constraints that calculates generation output levels and LMPs. The second is a simplified FTR auction formulation.

Lastly, this chapter lays the foundation for Chapter 5, which proposes two general models (CHIMPO and NO-SINTO) to correct the potential revenue inadequacy problem resulting from Braess's paradox and the use of SINTO, and for Chapters 6 and 7, where the models are applied to determine the extent of the risk in real systems.

3.2 Understanding LMP using a three-bus system

This section presents two cases of a simple three-bus example from [130] to explain LMPs. Figure 3.1 shows a three-bus system with a generator $G1$ connected to bus 1, generator $G2$ to bus 2, and a load L (demand) of 150 MW at bus 3. Generator $G1$ is the lowest-cost producer producing power at \$10/MW-h while generator $G2$ produces power at \$12/MW-h. Both generators have unlimited capacity. Additionally, the three transmission lines have the same impedances and have no capacity limit. For simplicity, transmission line losses are ignored.

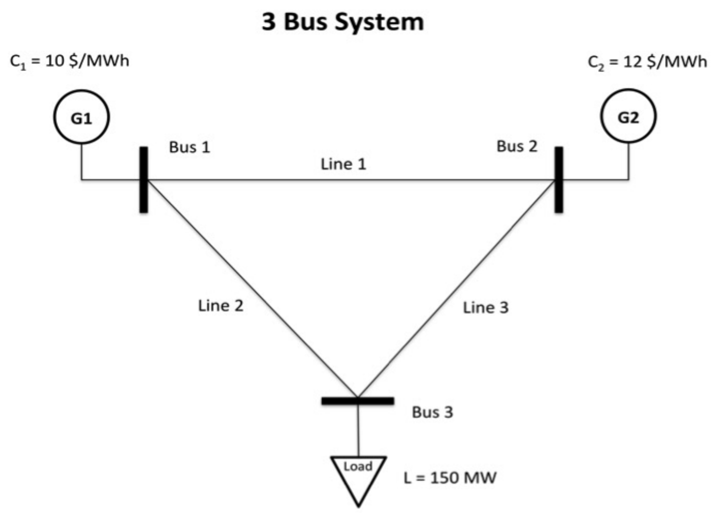


Figure 3.1: Three-bus circuit configuration

Figure 3.2 shows the least-cost dispatch solution. It is intuitive that the lowest cost to serve the load would come from generator $G1$ because its cost is less than that of generator $G2$. In this case, generator $G1$ produces 150 MW and injects it into bus 1. Generator $G2$ – being more expensive – does not dispatch power. From bus 1, the power has to travel to the load L, which is connected at bus 3. There are two possible paths that the power can travel through from bus 1 to bus 3: the first and most direct route goes through line 2 and the second path goes through lines 1 and 3. Twice as much power will travel through line 2 than the second path through lines 1 and 3 because lines 1 and 3 together have twice the impedance, which in an AC circuit is analogous to resistance in a DC circuit and impedes power flow. Impedance together with Kirchhoff's laws results in the phenomenon of parallel flows [131]: here, the power flow through path 1 (line 2) is 100 MW while it is 50 MW through path 2 (lines 1 and 3) since Kirchhoff's laws result in two-thirds of the power running through line 2.

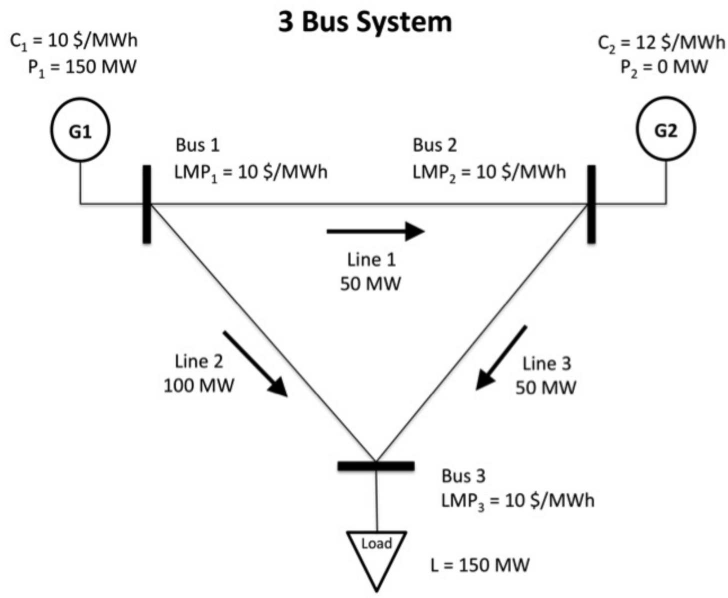


Figure 3.2: Least-cost dispatch with no constraints

The LMP is \$10/MW at each bus because generator $G1$ has the lowest cost and unlimited capacity, and there are no constrained lines in the transmission system. The cost to the load (customer payments) would be:

$$\frac{\$10}{\text{MW-h}} \times 150 \text{ MW-h} = \$1500$$

Generator $G1$ would be paid \$1500 for producing 150 MW at \$10/MW-h, and generator $G2$ would not be paid since it did not produce power.

It is important to note that if power were injected at bus 2, it would have two paths to reach the load at bus 3: the first through line 3 and the second through lines 1 and 2. Notice that power injected at bus 1 causes flow to travel from bus 1 to 2 whereas power injected at bus 2 causes a flow in the opposite direction. Injection contributions to line flows can be broken out this way due to the principle of superposition. After arbitrarily assigning a positive sign to a flow direction of a line, the flow contributions from each injection point can be algebraically summed to calculate the net flow. For example, if flow from bus 1 to 2 is positive and if generator $G1$ is producing 90 MW, the flow due to generator $G1$ would be 1/3 times 90 MW or 30 MW. The flow on line 1 due to generation $G2$ is 60 MW $\times -1/3$ or -20 MW. The net flow would be 30 MW + (-20 MW) or 10 MW from bus 1 to 2.

Now let us consider case 2, which has a 30 MW limit for line 1. In case 1, 50 MW traveled along line 1; however, now this flow is limited due to the 30 MW limit on line 1. The first 90 MW can be supplied from generator $G1$ before line 1 becomes constrained (90 MW $\times$ 1/3 = 30 MW). Generator $G2$ is needed to supply the rest of the load and prevent line 1 from exceeding its limit. For every megawatt that generator $G2$ injects into bus 2, a 1/3 MW counter-flow is created on line 1, reducing its flow. This allows generator $G1$ to increase its output and generate more power. This is desirable since generator $G1$ is less expensive than generator $G2$. The optimal solution is shown in Figure 3.3, with generator $G1$ producing 120 MW and generator $G2$ producing 30 MW.

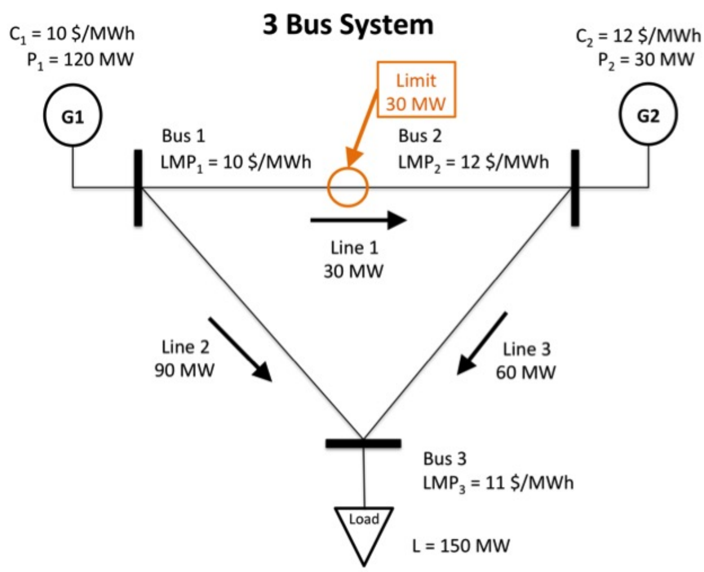


Figure 3.3: Least-cost dispatch with constraints

The LMP calculation for bus 1 remains the same at \$10/MW-h since generator $G1$ could supply a load at bus 1 for \$10/MW-h as long as the net power injection at that bus does not exceed 120 MW. The LMP for bus 2 is now \$12/MW-h since the line 1 constraint does not allow generator $G1$ to serve an additional load at bus 2. The LMP at bus 3 is \$11/MW-h because each megawatt supplied by generator $G2$ allows another megawatt from generator $G1$ to be produced; therefore, the marginal price of power at bus 3 is supplied by both generators $G1$ and $G2$ such that half is supplied by each. The LMP is calculated as the generator weighted average of generators $G1$ and $G2$ or $(.5 \times \$10/\text{MW-h}) + (.5 \times \$12/\text{MW-h}) = \$11/\text{MW-h}$. The financial settlements are as follows:

- Generator $G1 = \$10/\text{MW} \times 120\ \text{MW} = \$1200$
- Generator $G2 = \$12/\text{MW} \times 30\ \text{MW} = \$360$
- Load $L = \$11/\text{MW} \times 150\ \text{MW} = \$1650$

The total generation cost is \$1560, and the total amount that the load pays is \$1650. Finally, the congestion rents can be calculated from the difference between these two quantities: load payments minus generator receipts $= \$1650 - \$1500 = \$150$.

3.3 Braess's paradox

A German mathematician named Dietrich Braess discovered Braess's paradox when studying traffic networks. Braess's paper was initially written in German but translated into English by Anna Nagurney and Tina Wakolbinger of the University of Massachusetts, Amherst [39]. The paradox states that a transportation system's performance may decline in certain circumstances by adding capacity – in this case by building another road. He proved this by solving a Nash equilibrium for a traffic scenario using a Wheatstone bridge system where drivers acted in their own self-interest (minimizing their travel time).

3.3.1 Braess's paradox example

Below is a simple transportation example explaining Braess's paradox. The example presented is directly from [132, 133] and is presented here to give a general understanding of the paradox.

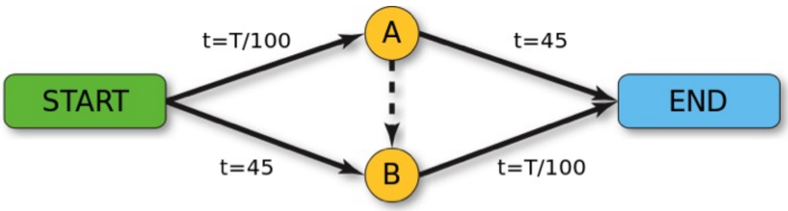


Figure 3.4: Braess's paradox transportation model example [134]

A Wheatstone bridge transportation system is shown in Figure 3.4. The new road represented by a dashed line is the Wheatstone bridge. In this example, 4000 drivers set off from the starting point to the finish. The travel time from the starting point to node A is dependent on the traffic flow whereas the travel time from the starting point to node B is dependent on road conditions. The travel times from nodes A and B are symmetrical but opposite to those from the starting point. The road from node A to the end point has a fixed time whereas the time to go from node B to the end point is a function of traffic flow.

An analysis of the system without the Wheatstone bridge where each driver is trying to minimize their own travel time yields the following results: 2000 drivers take the path from the starting point to node A to the end point, and 2000 drivers take the path from the starting point to node B to the end point. If everyone sets out from start to finish, then the total travel time for each driver is $T/100+45 = 2000/100+45$ or 65 minutes, where T is the number of travelers who take that road. The links that are flow dependent ($T/100$) are subject to congestion such that an increase in the number of drivers results in an increase in travel times. Since the road structure is symmetrical, a balance is reached when 2000 drivers take each path. Once the equilibrium is reached, no driver can unilaterally decrease their travel time further (the so-called user equilibrium). A well-known result is that the user equilibrium is not Pareto optimal (*i.e.*, it is inefficient).

However, if a new road is built from node A to node B that will take no time ($t = 0$), the outcome is different. In this case, the shortest time to either node A or B is from the starting point to node A, that is, the minimum of 4000/100 minutes and 45 minutes. Since there is no time penalty from node A to B, the shortest time to the end point from node B is also the minimum of 45 minutes and 4000/100 minutes. Each driver seeking to minimize their own travel time will select the path from the starting point to node A, from node A to node B, and finally from node B to the finish point, totaling 4000/100 + 4000/100, or 80 minutes. Thus, the addition of the Wheatstone bridge is socially suboptimal because the travel time for all drivers increased from 65 minutes to 80 minutes under the user equilibrium.

3.3.2 Braess's paradox in power systems

In his 2006 dissertation, Blumsack applies Braess's paradox to power systems, specifically as it pertains to market design policy incentives for transmission investment [37]. His research examined the characteristics of a Wheatstone bridge network (Figure 3.5) and how the unintended consequence of a decrease in system capacity can originate if a new line is constructed. Additionally, previous work in which adding a transmission line would reduce capacity can be found in [38, 135].

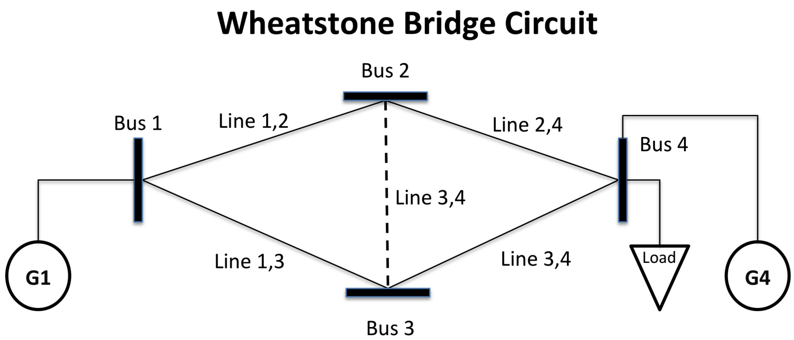


Figure 3.5: Wheatstone bridge circuit

Blumsack also studied the necessary and sufficient conditions for Braess's paradox to occur in a power system network. He concluded that the case for power systems is more restricted than in other networks such that the mere presence of a Wheatstone bridge circuit was neither a necessary nor a sufficient condition for Braess's paradox to occur. This finding complicates the identification of Braess's paradox in that, circuit configurations alone cannot be used to distinguish circuits that exhibit Braess's paradox. Other related research by Emily Fisher, et al. [14,127] exploits the effects of Braess's paradox by switching transmission lines in the dispatch optimization. This, in effect, lowers the cost of operating generators to meet demand. The current practice is that the transmission topology is not optimized and is configured to a normally operated state[1] regardless of the dispatch. In this case, the underlying advantage is due to Braess's paradox where switching transmission takes one or several lines out of service, thereby removing congestion and increasing the ability of the system to accommodate cheaper energy sources. The proposed research investigates the extent that Braess's paradox impacts FTR auctions and how SINTO compounds these impacts.

3.3.3 Electrical circuits exhibiting Braess's paradox

Electrical circuits exhibit a version of Braess's paradox. Unlike transport systems (where the paradox originates in the divergence between user equilibria and social cost minimization), in power markets, it originates from Kirchhoff's laws. Kirchhoff's laws cause power to flow in all parallel paths; however, the effect is similar: adding an additional link in the network can lower the capacity of the system. Two circuits are

[1]The normally operated state of a transmission system is where the system operator normally configures the transmission system for reliable operation by manipulating breakers.

introduced in this section; the first is a Wheatstone bridge circuit and the second is a parallel circuit containing mismatched lines where one has higher admittance and lower capacity than the other. The second circuit is a parallel high admittance low capacity (PHALC) circuit. Admittance is a characteristic of a line that is analogous to conductance in a direct current circuit. The reciprocal of admittance is impedance, and the reciprocal of conductance is resistance. Impedance reduces the current flow in an alternating current circuit or device.

It is important to note that these two circuits are not the only electrical circuits that exhibit Braess's paradox. They are presented because they will be used in an example later in the proposal.

3.3.4 Wheatstone bridge circuit

The Wheatstone bridge was invented by Samuel Hunter Christie but was named after Sir Charles Wheatstone, who publicized it. In its earliest use, the Wheatstone bridge was used to determine with precision the value of an unknown resistor, R_x. In the circuit in Figure 3.6, the line with the voltmeter is the Wheatstone bridge. When the voltmeter on the bridge reads zero, the two circuits are balanced, and the value on the rheostat (R_2) is equal to the value of the unknown resistance (R_x).

The Wheatstone bridge cannot be reduced to simpler series and parallel circuits. It is a unique circuit that frequently appears in power systems. Figure 3.7 shows two examples of Wheatstone bridges that appear in an actual system. In this case, the

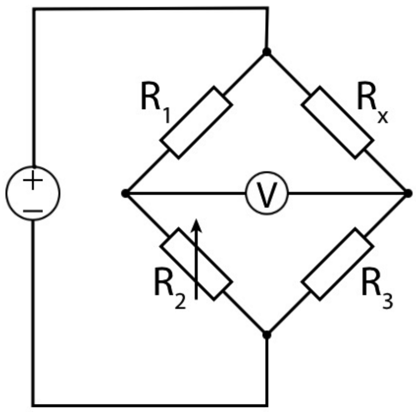


Figure 3.6: Wheatstone bridge circuit for determination of an unknown resistance (R_x) [136]

picture is of the transmission system in Houston, Texas, where the orange lines are 345 kV circuits, the blue lines are 138 kV circuits, and the yellow lines are 69 kV circuits.

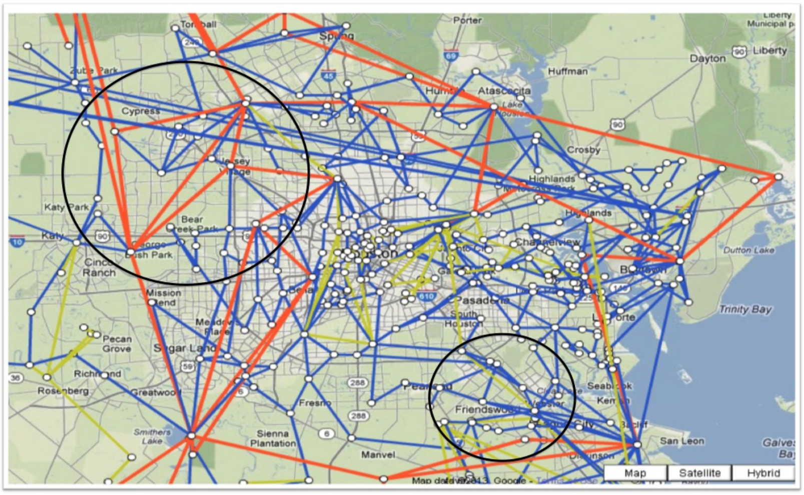


Figure 3.7: Geographic example of bridge circuits in Houston, Texas [137]

3.3.5 Parallel High Admittance Low Capacity circuits

A PHALC circuit is a simple example of a circuit that exhibits Braess's paradox. The circuit is composed of two parallel lines: one having a relatively higher admittance and a lower transmission line rating than the other. In short, more of the flow will take the path of higher admittance (or lower impedance), and because it contains a lower transmission line rating, it will become congested before the other line. A simple example is shown in Figure 3.8, where line B has twice the admittance, and half the line rating as line A. Line A's rating is 120 MW, and line B's rating is 60 MW. The most power that generator $G1$ can deliver to the load connected at bus 2 when both lines are in service is 60 MW + 30 MW, for a total of 90 MW. Since line B has twice the admittance, it will have twice as much flow as line A. The flow limitation is reached when line B reaches its limit of 60 MW and, at that point, there will be a 30 MW flow on line A. If line B is taken out of service, then the total transfer capability is 120 MW – line A's limit. In other words, generator $G1$ can transfer more power by taking line B out of service.

It may not seem reasonable that a transmission engineer would build such a circuit, but they exist because transmission systems are incrementally planned for load growth, reliability, or to accommodate new or retired generation. Variations of the PHALC circuit exist; for example, two areas that are connected by multiple tie lines

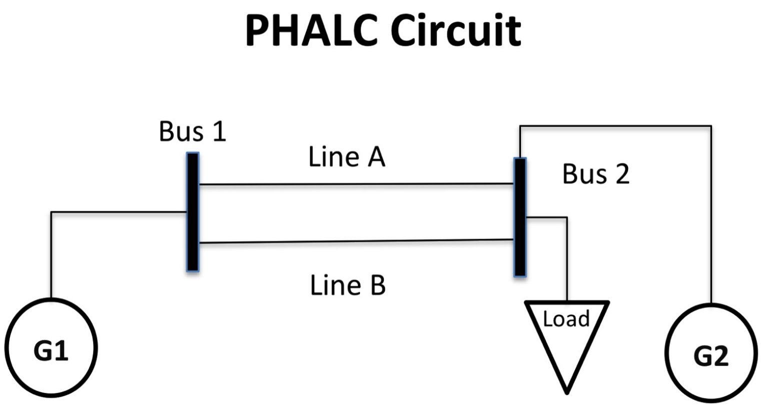


Figure 3.8: Parallel high admittance low capacity (PHALC) circuit

where the lowest rated line limits the transfer of power between areas. In another example, planners may not retire a transmission line even after a larger capacity line is built because the old line could still provide circuit redundancy for reliability.

3.4 The simultaneous imposition of non-coincidental transmission outages in power systems

Transmission owners schedule transmission outages by submitting an outage request to the RTO/ISO for review and approval. The RTO/ISO studies the outages to identify any reliability impacts and to coordinate outage requests with neighboring transmission companies. Transmission outages are not studied for minimizing market impacts or for how best to model them in the FTR auction process. Before an

FTR auction, the FTR modeling group at the RTO/ISO prepares the auction input data, which includes transmission outage assumptions. Figure 3.9 is an example Gantt chart illustrating five transmission outages scheduled for a typical month. This example represents the chronological order of the scheduled transmission outages.

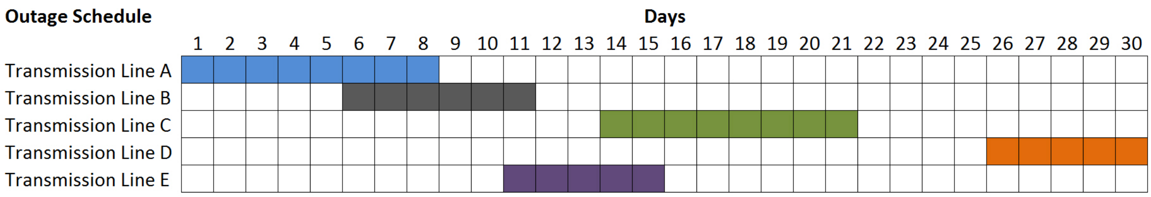


Figure 3.9: Example Gantt chart for transmission outages

The common practice when allocating FTRs is to model the outages concurrently in one transmission system representation as if they occur simultaneously, rather than chronologically, as shown in Figure 3.9. That is, all lines that have an outage (outages A through E) in Figure 3.9 are removed from the transmission topology as shown in Figure 3.10, which forms a set of capacity constraints in the FTR auction formulation.

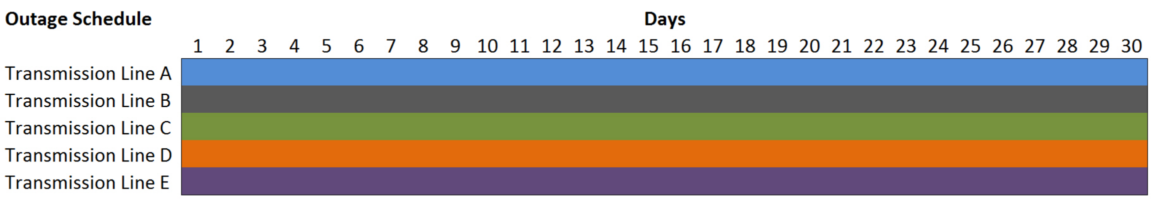


Figure 3.10: SINTO approximation: Gantt chart for transmission outages

To simplify the problem further, only outages of significant duration are included. For example, typically for a monthly auction, only outages lasting five days or greater are included. Table 3.1 lists the rules used by different RTO/ISOs for the inclusion of a transmission outage in FTR auctions.

Table 3.1: How RTO/ISOs include transmission outages for FTR auctions [24, 36, 138–141]

RTO/ISO	Transmission Outage Inclusion Rule
PJM	For the annual auction, lines taken out of model if an outage of two or more months is expected. **For monthly auction, take lines out if outage is equal or greater than five days, unless line is one critical to revenue adequacy. In which case, it is taken out of the model regardless of the duration of the outage.**
MISO	For annual process, lines taken out of model for the full season if , in one or more months of the season, a line outage is expected to last seven or more days and one of the days includes the 15th of the month. **For monthly process, lines taken out of model if outage is expected to last seven or more days and one of the days includes the 15th of the month.**
NEISO	**For 345 kV lines, will take lines of importance out of FNM for outages equal or greater than three days. Will derate constraint limits for outages less than three days.**
NYISO	**If a line is scheduled to be out for more than half the term of the upcoming TCC auction, it is a candidate to be removed from the full network model.** The NYISO then asks the transmission owner whether it should be taken out or remain in the model.
ERCOT	ERCOT will consider including Outages in the CRR Network Model that are scheduled to occur in the relevant time period and meet one or more of the following criteria: (i) **Consecutive or continuous approved or accepted Outages greater than or equal to five days**
CAISO	Each month the ISO will modify the CRR Full Network Model to **reflect the collective impact of transmission outages** that may have a significant impact on monthly CRR revenue adequacy. ... each month the ISO will select line outages **equal to or greater than a certain number of days** for analysis through a series of power flow tests.
SPP	...**outages greater than 120 hours in duration will be included in the model**, and outages less than or equal to 120 hours in duration will not be included in the model. If SPP determines that the inclusion or exclusion of an outage has significant detrimental impact to flow and/or overall funding, it may be excluded or included regardless of its duration.

Transmission outages are excluded from the FTR auction (line put back in service) only if they affect either reliability or the feasibility of the auction optimization, for example, see the Midwest Independent System Operator's FTR ARR Reports [142]. No consideration is made as to whether the transmission outage exhibits Braess's paradox (*i.e.*, increases the amount of FTRs that can be awarded) or if SINTO multiplies the effects of Braess's paradox. Typically, the FTR modeling group studies only whether the set of included outages is feasible, where feasible means that the set of outages does not create electrical islands. Electrical islands occur when at least one line does not connect a bus or a group of busses to the rest of the system. Rather than remove the line from the network, some RTO/ISOs, like the California ISO, may derate a line instead of modeling the line out of service. The derating will then be proportioned based on the number of days it is out of service over the total number of days in that month.

To illustrate SINTO, Figures 3.11 and 3.12 provide a visual comparison of the number of non-coincidental planned transmission outages (shown in red) occurring in a week versus a month in Houston (ERCOT) during May 2013. As can be seen, the topologies are very different – the latter figure being a graphical example of what is modeled for a monthly FTR auction. The different colors of the transmission lines indicate different voltage levels, with orange being 345 kV, blue 138 kV, and yellow 69 kV.

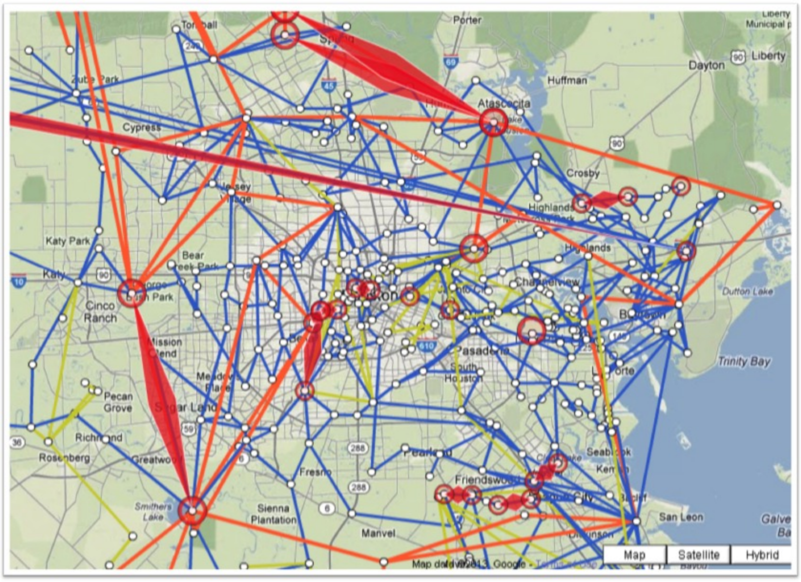


Figure 3.11: Map of ERCOT transmission outages for one week from May 22 to May 29, 2013 [137]

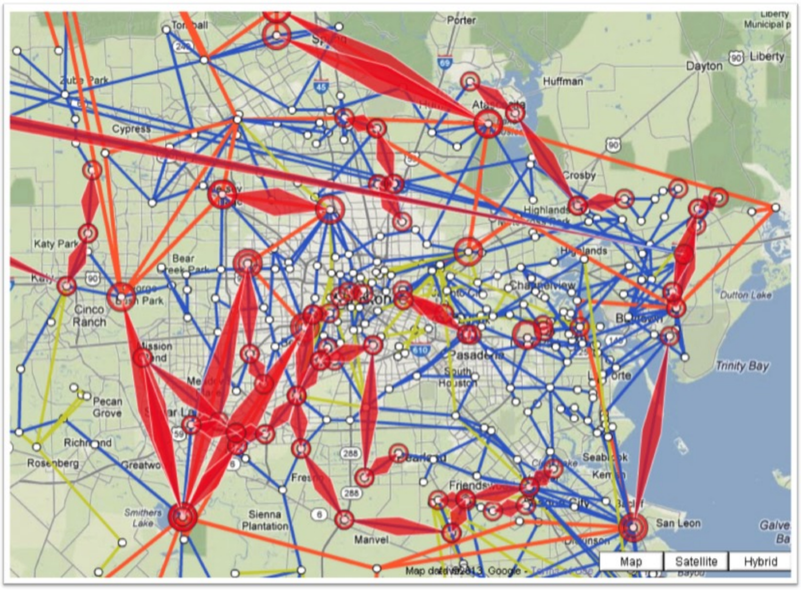


Figure 3.12: Map of ERCOT transmission outages for one month from May 1 to May 31, 2013 [137]

3.4.1 Genesis of SINTO

No literature exists on the SINTO methodology. Instead, a hypothesis is offered as to why SINTO was adopted. Before explaining the hypothesis, a very brief high-level exposition on fundamental power flow theory is presented to provide the necessary background for the hypothesis.

AC power flow routines solve a set of non-linear simultaneous equations where the unknowns include voltage angle, voltage magnitude, and real and reactive power flows over all lines and from all generators, given a set of real and reactive power demands. Kirchhoff's voltage and current laws are used to develop the set of equations, which involve complex numbers. Iterative numerical methods are used to solve the problem, such as the Gauss–Seidel, Newton–Raphson, and fast-decoupled algorithms [131].

The power flow problem can be solved more quickly if simplifying assumptions are made. In particular, for a linear DC load flow, the following three simplifying assumptions are made: the voltage magnitude is the same for each bus on the system by fixing the bus voltage magnitudes at a nominal voltage (flat voltage profile), voltage angles are very small, and the line resistance is negligible [131]. These assumptions make the load flow problem a linear problem that is much easier to solve. In all RTO/ISO markets, DC load flow methods are used for market applications, including dispatch and auctioning FTRs.

Even when using the simplifying DC load flow model, power flow calculations are computationally challenging and require a large computer memory capacity due to the actual size of transmission systems.[2] Shortcuts are needed to reduce the computational burden. Instead of performing several sequential load flows, one for each configuration of the network, a smaller and easier to solve model results from considering all the outages at once in a single load flow.

Regardless, of its origin, SINTO is practiced broadly in FTR auctions in the power industry. All RTO/ISOs in the United States use it in their FTR auction process. This type of industry adoption is considered good utility practice. FERC Order No. 888 defined "Good Utility Practice" in Section 1.14 of the pro forma OATT as follows:

> "Any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of

[2] Also, considering the number of contingencies to analyze.

> reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region" [143].

Note the definition does not require proof that the practice achieves the desired result or that it is optimal. Since no documentation exists on the practice, SINTO may never have been appropriately vetted to determine its effectiveness. It is also undetermined if it leads to other undesirable issues, like distorting the load flow results.

3.5 Model formulations

The first two formulations used in Chapter 4 to prove that SINTO can lead to revenue inadequacy (by overselling FTRs in FTR auctions) are presented and explained below. The first is a DC OPF used to simulate power market prices, generator dispatch levels, transmission constraints, and congestion cost. The second is a simplified FTR auction formulation (SINTO) used to calculate FTR awards, transmission constraints, and clearing prices. Further, a second FTR formulation is used that represents transmission constraints as they are operated to demonstrate that revenue adequacy is maintained. This formulation, called the CHIMPO FTR auction formulation, is presented in Formulation 5.1 (Chapter 5).

3.5.1 Generation dispatch formulation: DC optimal power flow

The dispatch formulation used in the circuit analysis that follows is a DC OPF formulation and is shown in Formulation 3.1. The formulation derived from [38] employs the susceptance matrix (B) and bus phase angles (θ) to calculate transmission line flows. The susceptance is the complex part of the admittance, and it plays a role like that of conductance in a DC circuit. The LMP is calculated as the dual of the Kirchhoff's current law (nodal energy balance) in constraint 3.1e.

Sets:

$\mathcal{I}_i^{\text{Conn}}$: All adjacent busses connect to bus i via lines

Indexes:

i, j: Bus index

Parameters:

C_i^{Cost}: Costs (usually, a generator's offer to sell energy (\$/MW-h))

G_i^{min}: Minimum generation output (MW)

G_i^{max}: Maximum generation output (MW)

Q_{ij}^{min}: Line flow minimum limit (MW)

Q_{ij}^{max}: Line flow maximum limit (MW)

B_{ij}: Line susceptance (mhos)

L_i: Load (MW)

Decision Variables:

g_i: Generator output (MW)

q_i^{Bus}: Net bus power injection or withdrawal (MW)

q_{ij}^{Line}: Line flow (MW)

θ_{ij}: Bus phase angle (radians)

The general dispatch model can be written as follows. Note that the following conditions apply to all equations where appropriate: $\forall i \in \mathcal{I}, \forall j \in \mathcal{I}$.

[3]Note that for non-generating buses i, that the values of $G_i^{\min}$ and $G_i^{\max}$ are zero.

Formulation 3.1: Dispatch Formulation

$$\min_{\substack{\boldsymbol{g},\boldsymbol{q}^{\text{Line}},\\ \boldsymbol{q}^{\text{Bus}},\boldsymbol{\theta}}} \quad \sum_{i\in\mathcal{I}} C_i^{\text{Cost}} g_i \tag{3.1a}$$

Subject to:

Generator Operating Limits:[3]

$$G_i^{\min} \leq g_i \leq G_i^{\max} \tag{3.1b}$$

Transmission Line Limits:

$$Q_{ij}^{\min} \leq q_{ij}^{\text{Line}} \leq Q_{ij}^{\max}, \qquad j \in \mathcal{I}_i^{\text{Conn}}, j > i \tag{3.1c}$$

Net Flow:

$$g_i + q_i^{\text{Bus}} = L_i \tag{3.1d}$$

Kirchhoff's Current Law whose dual is the locational marginal price:

$$\sum_{\substack{j\in\mathcal{I}_i^{\text{Conn}}\\ j<i}} -q_{ij}^{\text{Line}} + \sum_{\substack{j\in\mathcal{I}_i^{\text{Conn}}\\ j>i}} q_{ij}^{\text{Line}} + q_i^{\text{Bus}} = 0, \tag{3.1e}$$

Line Flow Phase Angle:

$$B_{ij}\left(\theta_i - \theta_j\right) = q_{ij}^{\text{Line}}, \qquad \forall j \in \mathcal{I}_i^{\text{Conn}}, j > i \tag{3.1f}$$

3.5.2 SINTO FTR auction formulation

The FTR auction formulation in Formulation 3.2 is inspired by the above dispatch formulation [12]. The FTR auction objective function is to maximize FTR as-bid bids that are simultaneously feasible. An FTR can be thought of as a vector containing four components: bid (C_s^{Bid}), bid quantity (F_s^{max}), and a path with a source bus (i) and sink bus (j). f_s is a decision variable and M_{is} converts the bids into power injections and withdrawals to determine line flows and simultaneous feasibility.

Additional notation is as follows:

Index:

s: FTR Bid Index

Parameters:

C_s^{Bid}: FTR Bids (\$/MW-h)

F_s^{max}: FTR quantity maximum limit (MW)

M_{is}: FTR mapping matrix converting FTR bid s into bus i, j injections and withdrawals

S: Total Number of Bids (MW)

Decision Variables:

f_s: FTR Bid Vector including source (i), sink (j), and quantity (MW)

The SINTO model can be written as follows. Note that the following conditions apply to all equations where appropriate: $\forall i \in \mathcal{I}, \forall j \in \mathcal{I}$.

Formulation 3.2: FTR Auction Formulation

$$\max_{\substack{\boldsymbol{f},\boldsymbol{q}^{\text{Line}},\\ \boldsymbol{q}^{\text{Bus}},\boldsymbol{\theta}}} \quad \sum_{s\in\mathcal{S}} C_s^{\text{Bid}} f_s \tag{3.2a}$$

Subject to:

FTR – Node Mapping:

$$\sum_{s\in\mathcal{S}} M_{is} f_s = q_i^{\text{Bus}} \tag{3.2b}$$

FTR Bid Quantity Limits:

$$0 \leq f_s \leq F_s^{\max} \tag{3.2c}$$

Transmission Line Limits:

$$Q_{ij}^{\min} \leq q_{ij}^{\text{Line}} \leq Q_{ij}^{\max}, \qquad j \in \mathcal{I}_i^{\text{Conn}}, j > i \tag{3.2d}$$

Kirchhoff's Current Law:

$$\sum_{\substack{j\in\mathcal{I}_i^{\text{Conn}}\\ j<i}} -q_{ij}^{\text{Line}} + \sum_{\substack{j\in\mathcal{I}_i^{\text{Conn}}\\ j>i}} q_{ij}^{\text{Line}} + q_i^{\text{Bus}} = 0, \tag{3.2e}$$

Line Flow Phase Angle:

$$B_{ij}\left(\theta_i - \theta_j\right) = q_{ij}^{\text{Line}}, \qquad j \in \mathcal{I}_i^{\text{Conn}}, j > i \tag{3.2f}$$

Chapter 4

Revenue Inadequacy Caused by Braess's Paradox and SINTO

In this chapter, a simple case study will be used to demonstrate that Braess's paradox and SINTO in FTR auctions can lead to revenue inadequacy. The example that follows shows how SINTO can in some cases exaggerate transmission capacity relative to actual system capacity. This is accomplished comparing two cases: the first using SINTO in the FTR auction and the second using a multi-topology (CHIMPO) approach to develop transmission constraints that more accurately reflect operational topologies.

The Wheatstone bridge and the PHALC circuits demonstrate that it is possible to increase transmission system capacity by taking a line out of service. The circuit in Figure 4.1 places a PHALC circuit and a Wheatstone bridge circuit in series to establish that SINTO can, in fact, increase transmission system capacity, which results in revenue inadequacy. Selling too many FTRs, which clear the auction at a lower price, causes this revenue inadequacy. This section examines two cases. The first case represents the current practice of SINTO in FTR auctions. In the second case, the proposed multi-topology FTR auction formulation, called the chronological imposition of planned outages (CHIMPO), is employed. This formulation represents the system topology better at various times during the total period. In the example, there are four periods, and each can be considered a dispatch period and a settlement period. For simplicity in this example, each period is an hour, and a calendar strip consists of four periods or four hours. FTRs are auctioned off by a calendar strip that includes all four periods. This is like an actual market where power is settled every hour and FTRs are sold by monthly calendar strips.

4.1 Circuit description

Figure 4.1 shows the circuit that will be used in this example and Table 4.1 contains the circuit's parameters. There are two generators such that generator $G1$ is the lowest-cost producer with a cost of \$15/MW-h and generator $G5$ has a cost of \$20/MW-h. For simplicity, each generator is assumed to have no maximum generation capacity limit. There is only one load, and it is connected at bus 5 where the higher cost generator $G5$ is located. The load in all four hours is equal to 120 MW. The most economic power flow is from generator 1, connected at bus 1, to the load connected at bus 5. Also, note that generator $G5$ can deliver to the load at bus 5 without causing power flow in the system.

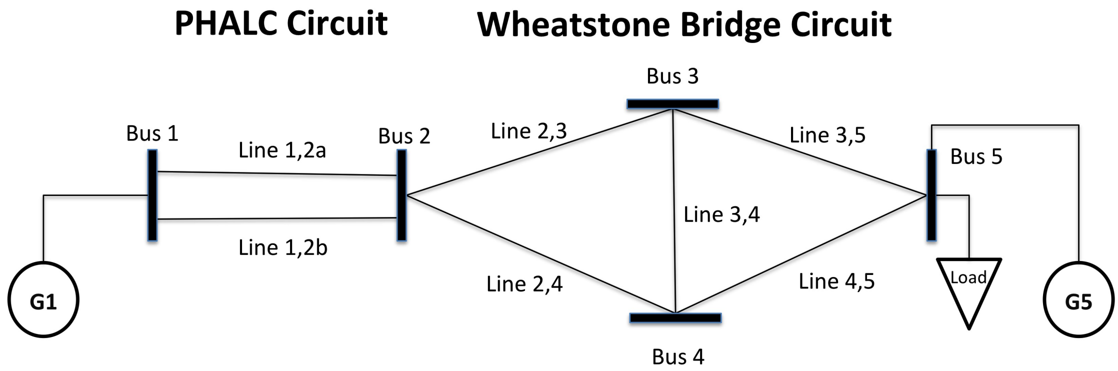


Figure 4.1: Hybrid PHALC and Wheatstone bridge circuit

Table 4.1: Hybrid PHALC and Wheatstone bridge circuit parameters

Line	**R (per unit)**	**X (per unit)**	**Limit (MW)**
Line1,2a	0	0.00286	140
Line1,2b	0	0.00143	60
Line 2,3	0	0.00143	70
Line 2,4	0	0.00286	70
Line 3,4	0	0.00001	200
Line 3,5	0	0.00286	70
Line 4,5	0	0.00143	70

4.2 System dispatch LMP calculation

The total auction period (calendar strip) contains four one-hour periods and in each period transmission lines can be scheduled out of service. Table 4.2 displays the scheduled transmission outages. Periods 1 and 2 have no transmission outages scheduled. Line 1,2b is scheduled out of service for period 3 and line 3,4 for period 4.

Table 4.2: Planned transmission outage schedule

Period	1	2	3	4
Line 1,2b	–	–	X	–
Line 3,4	–	–	–	X

Table 4.3 contains the LMP results for each period using the dispatch formulation in Formulation 3.1.

Table 4.3: Dispatch pricing and congestion spreads from bus 5 to bus 1

Bus	**Locational Marginal Prices**				
Period	1	2	3	4	
Bus 1	$15.00	$15.00	$15.00	$15.00	
Bus 2	$20.00	$20.00	$15.00	$20.00	
Bus 3	$20.00	$20.00	$20.00	$20.00	
Bus 4	$20.00	$20.00	$20.00	$20.00	
Bus 5	$20.00	$20.00	$20.00	$20.00	
Congestion Spreads					**Ave Spreads**
Bus 5 to Bus 1	$5.00	$5.00	$5.00	$5.00	$5.00

If there were no congestion, the bus LMPs for each period would be the same; however, note that this is not the situation. Congestion appears in each period, even with all the lines placed in service (periods 1 and 2). Of particular interest is the price difference from bus 1 to bus 5, since generator $G1$ is the lowest-cost generator and is fully exposed to the congestion. The bus 1 to bus 5 price difference for each period is shown at the bottom of Table 4.3. In each period, the price difference is $5/MW-h, so the average congestion for the total period is $5/MW-h.

Table 4.4 displays the generation dispatched during each period. Notice that generator $G1$, the least expensive generator, does not supply all of the power, even though generator $G1$ has enough capacity to supply the load. This indicates that the transmission system could not deliver any more power from generator $G1$ and was constrained in every period.

Table 4.4: Generator dispatch levels

Generator	**Dispatch (MW)**			
Period	1	2	3	4
$G1$	90	90	105	90
$G5$	30	30	15	30

4.3 Case 1: FTR auction results with SINTO

Two FTR auction bidders needed to be developed for this example. The first is a hedger who owns generator $G1$ and is simply attempting to hedge[1] generator $G1$. The second bidder is a speculator who has no physical position (generation or load) in the power market and is attempting to capitalize on arbitrage opportunities. The hedger's strategy is risk management to protect their physical position – the cost of selling power from bus 1 to the load at bus 5 from uncertain transmission

[1]As explained in Chapter 1, FTRs hedge the FTR holder from exposure to price differences between two nodes by providing an additional payment stream equal to the amount of congestion rents charged between the two nodes.

system events. The speculator's strategy is to get a return on investment such that the FTR payments received (from congestion rents) are greater than the price paid for the FTR. Assuming that both participants have a perfect LMP forecast, as listed in Table 4.3, the hedger, would be willing to bid at least \$5/MW-h. This is because the hedger is not opportunistic and requires no return on investment other than the payment stream to hedge their position. Unlike the hedger, the speculator needs to bid less than the forecast spread to gain a return; otherwise, the return would be zero. In this example, the speculator is looking to gain a \$1 return on investment, so they would bid \$4/MW-h for an FTR that sources at bus 1 and sinks at bus 5.

Table 4.5 illustrates how the transmission outages are modeled in the FTR auction single-period topology. On the left is the transmission outage schedule and on the right is a single period containing both scheduled outages, which are modeled simultaneously. That is, the SINTO FTR model imposes the outages of both lines 1,2b and 3,4 at the same time, even though in reality the maintenance outages occur in different periods. The SINTO approach is the same as modeling both transmission outages for the duration of all four hours.

Table 4.5: Comparison of planned outage schedule and how transmission outages are modeled in the FTR auction model (SINTO)

Transmission Outage Schedule

Period	1	2	3	4
Line 1,2b	–	–	X	–
Line 3,4	–	–	–	X

$\Rightarrow$

FTR Model – SINTO

T_1
X
X

The FTR auction formulation (Formulation 3.2) is used to model the non-coincidental transmission outages simultaneously. The FTR auction is cleared as follows: both the hedger's and speculator's bids clear at a price of \$4/MW-h. Therefore, the speculator's bid sets the price. The hedger is awarded 120 MW and the speculator 20 MW for a calendar strip that includes all four periods. Table 4.6 displays the awarded FTR auction settlements for each FTR holder. The amount owed to the RTO/ISO is the total number of FTRs awarded per period × 4 periods × the FTR auction clearing price. For the hedger, the amount owed would be 120 FTR/h × 4 h × \$4 = \$1920; whereas the FTR auction cost for the speculator is 20 FTR/h × 4 h × \$4 = \$320.

Table 4.6: Case 1: FTR auction awards and total cost to purchase FTRs

Bidder	**FTR Awards (MW)**				
Period	1	2	3	4	
Hedger	120	120	120	120	
Speculator	20	20	20	20	
FTR Clearing Price	\$4.00	\$4.00	\$4.00	\$4.00	–
Bidder	**FTR Cost**				**FTR Total Cost**
Period	1	2	3	4	
Hedger	\$480.00	\$480.00	\$480.00	\$480.00	\$1920.00
Speculator	\$80.00	\$80.00	\$80.00	\$80.00	\$320.00
					\$2240.00

Using the LMP values forecast in Table 4.3 as actual LMPs, the FTR payouts to the FTR holders are shown in Table 4.7 with the hedger receiving \$2400 and the speculator receiving \$400. The table also shows the profit received by subtracting the FTR cost from the FTR auction payout. Both the hedger and the speculator make a profit.

Table 4.7: Case 1: FTR holder payouts and profits (FTR Payout – FTR Cost)

Bidder	**FTR Payout**				**Total FTR Payout**
Period	1	2	3	4	
Hedger	$600.00	$600.00	$600.00	$600.00	$2400.00
Speculator	$100.00	$100.00	$100.00	$100.00	$400.00
					$2800.00

Bidder	**Difference (Profit)**				**Total Profit**
Period	1	2	3	4	
Hedger	$120.00	$120.00	$120.00	$120.00	$480.00
Speculator	$20.00	$20.00	$20.00	$20.00	$80.00
					$560.00

4.3.1 Case 1: Revenue adequacy

RTO/ISOs are non-profit organizations that take no financial positions – meaning that they are revenue neutral. Ratepayers pay their net expenses through a regulated tariff, and for any losses or gains due to congestion and FTRs. Table 4.8 shows the amount of money that the ISO collects from the load and the amount it pays to the generators. These charges and payments are calculated by multiplying the amount of power either supplied or consumed (quantity) by the respective LMP. This result is now revenue inadequate as indicated by the $925.00 deficit if the FTR holders are fully paid. Thus, SINTO has given away too many transmission rights because of Braess's paradox.

Interestingly enough, both the speculator and the hedger made a profit from the auction although the FTRs are revenue inadequate. Better yet, this revenue

Table 4.8: Case 1: Revenue adequacy calculation

Entity	**RTO/ISO Settlements**					
Period	1	2	3	4	Totals	
Load	\$2400.00	\$2400.00	\$2400.00	\$2400.00	\$9600.00	Collected
$G1$	\$1350.00	\$1350.00	\$1575.00	\$1350.00	\$5625.00	Paid
$G5$	\$600.00	\$600.00	\$300.00	\$600.00	\$2100.00	Paid
					\$1875.00	Congestion Rents
					\$2800.00	FTR Payout
					(\$925.00)	Revenue Adequacy

inadequacy is observed, despite the seemingly conservative approach of employing SINTO to reduce system capacity and prevent FTR over-awarding. In fact, imposing all the outages at once has increased system capacity, not conservatively decreased it.

4.4 Case 2: FTR auction results using the proposed multi-topology CHIMPO formulation

Now consider case 2, which uses the proposed multi-topology formulation (Formulation 5.1 in Chapter 5) to form constraints that better represent system operations. In this case, the transmission outages are modeled by forming three sets of topological constraints as shown on the right side of Table 4.9. Essentially, the multi-topology topological constraints limit FTR awards to the most limiting circuit capacity during any of the periods.

The FTR awards and clearing price for a path from bus 1 to bus 5 are displayed

Table 4.9: Comparison of planned outage schedule and how transmission outages are modeled in the FTR auction model (CHIMPO)

Transmission Outage Schedule

Period	1	2	3	4
Line 1,2b			X	
Line 3,4				X

⇒

FTR Model – CHIMPO

T_1	T_2	T_3
	X	
		X

in Table 4.10. In this case, the FTR awards are 90 MW for the hedger and 0 MW for the speculator. These are down from SINTO's awards of 120 MW for the hedger and 20 MW for the speculator. Also, note that now the hedger sets the clearing price and that the hedger has to pay more for an FTR, which has increased from $4 (case 1) to $5.

Table 4.10: Case 2: FTR auction awards

Bidder	**FTR Awards (MW)**			
Period	1	2	3	4
Hedger	90	90	90	90
Speculator	0	0	0	0
FTR Clearing Price	$5.00	$5.00	$5.00	$5.00

Table 4.11 displays the FTR auction settlements. For the hedger, this would be 90 FTR/h × 4 h × $5 = $1800; whereas the FTR auction cost for the speculator is $0 since they were not awarded any FTRs.

Table 4.11: Case 2: Total cost of purchasing FTRs

Bidder	**FTR Cost**				**FTR Total Cost**
Period	1	2	3	4	
Hedger	$450.00	$450.00	$450.00	$450.00	$1800.00
Speculator	$0.00	$0.00	$0.00	$0.00	$0.00
					$1800.00

Using the LMP values forecast in Table 4.4 as actual LMPs, the FTR payouts to the FTR holders are shown in Table 4.12. The hedger receives $1800 and the speculator receives $0. The table also shows the profit received by subtracting the FTR cost from the FTR auction payout. The hedger recovers enough money from the FTR payments to exactly hedge the congestion cost incurred from bus 1 to bus 5, because their bid exactly equaled the expected price difference.

Table 4.12: Case 2: FTR holder payouts and profits (FTR Payout – FTR Cost)

Bidder	**FTR Payout**				**Total FTR Payout**
Period	1	2	3	4	
Hedger	$450.00	$450.00	$450.00	$450.00	$1800.00
Speculator	$0	$0	$0	$0	$0
					$1800.00

Bidder	**Difference (Profit)**				**Total Profit**
Period	1	2	3	4	
Hedger	$0	$0	$0	$0	$0
Speculator	$0	$0	$0	$0	$0
					$0

4.4.1 Case 2: Revenue adequacy

Table 4.13 provides the power market settlements for generators $G1$ and $G5$ and the load for the total period. The differences that the RTO/ISO paid to the generators and collected for the load is now enough to fund the FTRs fully and stay revenue adequate. The ISO receives $75 more in congestion revenues than it pays out to FTR holders.

Table 4.13: Case 2: Revenue adequacy calculation

Entity	**RTO/ISO Settlements**					
Period	1	2	3	4	Totals	
Load	\$2400.00	\$2400.00	\$2400.00	\$2400.00	\$9600.00	Collected
$G1$	\$1350.00	\$1350.00	\$1575.00	\$1350.00	\$5625.00	Paid
$G5$	\$600.00	\$600.00	\$300.00	\$600.00	\$2100.00	Paid
					\$1875.00	Congestion Rents
					\$1800.00	FTR Payout
					\$75.00	Revenue Adequacy

4.5 Summary

Case 1 in this example revealed how SINTO could lead to revenue inadequacy when outages in circuits that exhibit Braess's paradox impact each other. Case 2 employed a multi-topology formulation that better represented the multiple topologies during the total period. The multi-topology model added transmission constraints that conservatively limited FTR over-awarding. This example presents only the case where the transmission outages exhibited Braess's paradox. However, many if not most cases of transmission outages will lead to reduced rather than increased capacity. The proposed multi-topology formulation would still be able to capture these capacity reductions appropriately to limit FTR awards. Lastly, a contributing factor to revenue inadequacy, in addition to the Braess's paradox–SINTO interaction, is the market rule that requires FTRs to be auctioned in calendar strips. An FTR calendar-strip award that is limited by the most limiting transmission constraint during the period is an overly restrictive practice that reduces the FTR capacity during periods when FTRs are feasible. However, the economic benefits of relaxing this restriction and awarding

FTR for periods smaller than a month is left for future research.

4.6 Braess's paradox circuit formation possibilities

The combined series PHALC circuit and Wheatstone bridge circuit modeled in this example is one of many possible circuit formations. A circuit can contain any combination of these circuits including the basic formations (series, parallel, or combination series-parallel circuits), which may interact with each other. Further, these circuits may exist within other Wheatstone bridges or other types of mesh circuit that cannot be neatly decomposed into series and parallel circuits. Moreover, the difficulty of identifying Braess's paradox increases when taking into account that actual power systems have network flows from multiple generators to multiple loads. In Chapter 5, two formulations that implicitly reduce the meshed/nested Braess's paradox and SINTO effects are presented.

Chapter 5

Proposed Solutions

This portion of the thesis offers two formulations, which are both pragmatic solutions that address issues derived from Braess's paradox in SINTO-based FTR auctions. They are considered practical because present commercial software packages can be reconfigured to the new formulation and thus, RTOs may readily implement them in today's FTR markets. To this end, the two formulations are tested and analyzed in the case study that follows (Chapters 6 and 7).

Then, Formulation 3.2 is modified to include the ability to consider multiple topologies in the FTR auctions, by adding an index for topologies t. Let the sets $\mathcal{T}^{\text{SINTO}}$, $\mathcal{T}^{\text{CHIMPO}}$, and $\mathcal{T}^{\text{NO-SINTO}}$ denote the sets of topologies considered in the SINTO, CHIMPO and NO-SINTO formulations (described in the subsequent sections) for the auction period, respectively. Briefly, the SINTO formulation[1] considers

[1]The SINTO model in Formulation 3.2 is a special case of the presented Formulation 5.1, where t is a single topology SINTO.

a single topology, *i.e.*, $\mathcal{T}^{\text{SINTO}} = \{\text{SINTO}\}$. The NO-SINTO formulation considers two topologies: The SINTO and normal operation (*i.e.*, no scheduled outages) topologies, respectively. Therefore, $\mathcal{T}^{\text{NO}-\text{SINTO}} = \{\text{NO}, \text{SINTO}\}$, where the topology NO indicates the normal operations topology. Finally, the CHIMPO formulation considers each unique topology that occurs during the FTR auction planning period, which may or may not include the NO and SINTO topologies.

Note that the following conditions apply to all equations where appropriate: $\forall i \in \mathcal{I}, \forall j \in \mathcal{I}$. In addition, the following conditions are included for the SINTO, CHIMPO and NO-SINTO models, respectively, depending on the model that is solved: $\forall t \in \mathcal{T}^{\text{SINTO}}$, $\forall t \in \mathcal{T}^{\text{CHIMPO}}$, and $\forall t \in \mathcal{T}^{\text{NO}-\text{SINTO}}$. The details of the CHIMPO and NO-SINTO models are described in the subsequent subsections.

This section is organized as follows: Section 5.1 describes the multi-topology CHIMPO FTR auction formulation. In Section 5.2, a simple but novel modification based on Braess's paradox is made to the CHIMPO formulation to give a practical implementation called the NO-SINTO formulation.

5.1 Chronological Imposition of Planned Outages (CHIMPO) formulation

Multi-period FTR auction models are in use today, but only to accommodate multiple trading periods (*e.g.*, peak-weekday, peak-weekend, off-peak and 24-hour, Formulation 5.1: Multi-topology FTR Auction Formulation

$$\max_{\substack{\boldsymbol{f},\boldsymbol{q}^{\text{Line}},\\ \boldsymbol{q}^{\text{Bus}},\boldsymbol{\theta}}} \quad \sum_{s\in\mathcal{S}} C_s^{\text{Bid}} f_s \tag{5.1a}$$

Subject to:

FTR – Node Mapping:

$$\sum_{s\in\mathcal{S}} M_{is} f_s = q_i^{\text{Bus}} \tag{5.1b}$$

FTR Bid Quantity Limits:

$$0 \leq f_s \leq F_s^{\max} \tag{5.1c}$$

Transmission Line Limits:

$$Q_{ij}^{\min} \leq q_{ijt}^{\text{Line}} \leq Q_{ij}^{\max}, \qquad j \in \mathcal{I}_i^{\text{Conn}}, j > i \tag{5.1d}$$

Kirchhoff's Current Law:

$$\sum_{\substack{j\in\mathcal{I}_i^{\text{Conn}}\\ j<i}} -q_{ijt}^{\text{Line}} + \sum_{\substack{j\in\mathcal{I}_i^{\text{Conn}}\\ j>i}} q_{ijt}^{\text{Line}} + q_i^{\text{Bus}} = 0, \tag{5.1e}$$

Line Flow Phase Angle:

$$B_{ijt}\left(\theta_{it} - \theta_{jt}\right) = q_{ijt}^{\text{Line}}, \qquad j \in \mathcal{I}_i^{\text{Conn}}, j > i \tag{5.1f}$$

or around-the-clock periods) [144]. The model in this section is the first proposed practical solution to specifically address the effects of Braess's paradox and SINTO by modifying the FTR auction formulation to include transmission constraints that account for all periods where the transmission topology changes. This formulation creates transmission system constraints for all changes in topology during the auction period that is modeled by grouping similar hourly configurations.[2] The possibility that Braess's paradox causes an over-allocation of FTRs is mitigated because all system configurations are accurately represented in the transmission constraints, including the system without transmission outages (if there are none in any hour).

In Formulation 5.1, note the addition of the t index (compared to formulation 3.2), which represents a new set of constraints for every period where the transmission topology changes. The formulation is called the chronological imposition of planned outages (CHIMPO) since it simulates the chronological order of the planned transmission outages.

5.2 NO-SINTO formulation

One potential shortcoming of the CHIMPO model is that the problem size is proportional to the number of transmission topologies modeled. This is due to the additional sets of transmission constraints from each topology change. For realistic systems, the additional constraints and variables may make practical implementation impossible due to issues such as increased computational time. Table 5.1 provides ERCOT CRR auction bid statistics for the period from May 2013 through to May 2014. This data provides a sense of the actual size of the objective function, as the

[2]A multi-topology FTR auction formulation utilizing transmission switching to model transmission outages in its SFT is presented in [129]. However it is not proposed as a direct solution to the impacts of Braess's paradox and SINTO, but rather, to better model outages that reduce transmission capacity.

table displays the number of CRR buy offers and sell bids that make up the number of decision variables. During this period, the average number of FTR decision variables for Formulation 5.1 would be 144,289. The total number of decision variables is larger because there are flow and angle variables for each month as well. While it is understood that this is not the largest optimization problem, it is substantial considering the tight market deadlines for computing, analyzing, and validating the results.

Table 5.1: Statistics of actual CRR auction bids

	Buy Bids		Sell Offers		
Month	**Number**	**Sum(MW)**	**Number**	**Sum(MW)**	**Decision Variables**
May-13	137,922	1,844,191	7,437	34,768	145,359
Jun-13	139,104	2,136,477	6,518	32,135	145,622
Jul-13	162,001	1,997,517	8,948	38,365	170,949
Aug-13	141,346	1,933,015	9,159	42,859	150,505
Sep-13	139,737	1,761,129	9,849	46,724	149,586
Oct-13	156,288	1,792,870	8,681	46,672	164,969
Nov-13	148,971	1,795,427	9,358	47,468	158,329
Dec-13	102,209	1,364,297	10,389	49,671	112,598
Jan-14	135,689	1,880,676	9,651	51,159	145,340
Feb-14	114,543	2,066,313	12,632	51,334	127,175
Mar-14	115,186	1,651,618	8,258	39,283	123,444
Apr-14	137,646	1,892,568	8,533	41,857	146,179
May-14	126,701	1,766,542	9,007	46,099	135,708
				Average DV	144,289

Table 5.2 displays the attributes that make up the transmission constraints. An estimate is provided in Table 5.3 of both the number of bid constraints and transmission system constraints for the SINTO, CHIMPO, and NO-SINTO formulations based on the data in Table 5.2. For the SINTO formulation, the calculation in Table 5.3 (line #8) shows that the estimated total number of constraints in the May

Table 5.2: May 2013 CRR auction data statistics

Base Case Statistics	Base case	Auction Data
Buses	6890	
Lines	6966	
Transformers	668	
Monitored Lines and Transformers		7125
Contingencies		3628
Bidding periods (Time-of-use)		4
Interfaces		3
Bidding points		488
Number of Planned Transmission Line and Transmformer Outages	65	

2013 CRR auction was 77,715,243.

If there are nine non-coincident outage periods (plus the no-outage case), the number of constraints increases by ten times to 775,844,199; see Table 5.3 (line #12). To reduce the number of constraints, a NO-SINTO FTR auction is introduced to remedy the Braess's paradox and SINTO situation. In general, Braess's paradox and SINTO can create capacity that over-awards FTRs; therefore, an alternate solution is proposed to limit the overcapacity created by modeling only two configurations: one with normal operations considering no transmission outages (normal operations or NO) and the other with SINTO. The number of constraints in the practical NO-SINTO formulation reduces to 155,285,127, which may be doable considering auction deadlines; see Table 5.3 (line # 17).

The example from Chapter 4 that uses both a PHALC circuit in series with a Wheatstone bridge circuit is used to explain the rationale for this formulation. In that example, the FTR auction optimization tries to award as many FTRs that the transmission constraints allow at the highest price. Since the objective function

Table 5.3: Comparison of estimated number of constraints for the SINTO, CHIMPO, and NO-SINTO CRR auction formulations

Line #	Constraints Calculation (May 2013 ERCOT CRR Auction)	Comments		Values
1	Monitored Lines & Transformers X Contingencies	Contingency Constraints		25,849,500
2	Monitored Lines & Transformers	Base Case Constraints	+	7,125
3	Interface Constraints	Base Case Constraints	+	3
4	Total Transmission Constraints (single period)	1 Bid Period		25,856,628
5	ERCOT has 4 Bidding options for 3 periods		x	3
6	Total Transmission Constraints (three periods)	3 Bidding Periods		**77,569,884**
7	Bid and Offer Constraints (May 2013)	Bid and Offer Limits	+	145,359
8	**Total number of Actual CRR Auction Formulation Constraints**			**77,715,243**
	Constraints Calculation with Proposed Theoretical Formulation	**Comments**		**Values**
9	Multiperiod Transmission Constraints (Proposed Formulation 1)	is equal to **n** x 77,569,884 (Line #6) wherer **n** is the number of periods where the transmission system topology is different due to changes in transmission outages		
10	Total Transmission Constraints in proposed Ideal formulation **n**=10 topologies	Estimate with 10 non-coincidental outages		775,698,840
11	Bid and Offer Constraints (May 2013)	Bid and Offer Limits (Line #7)	+	145,359
12	**Total number of constraints in proposed Ideal Formulation**			**775,844,199**
	Constraints Calculation with Proposed Practical Formualtion	**Comments**		**Values**
13	Number of transmission constraint using one topology and three periods	(From Line #6)		77,569,884
14	Two Transmission Topologies: SINTO and without transmission outages	Double the transmission constraints	x	2
15	Total Transmission Constraints with Proposed Practical Formulation	3 Bidding Periods		**155,139,768**
16	Bid and Offer Constraints (May 2013)	Bid and Offer Limits (Line #7)	+	145,359
17	**Total number of constraints in proposed two period formulation**			**155,285,127**

maximizes the auction value (the set of simultaneously feasible FTRs generating the largest sum of as-bid bids), the most restrictive topology would limit the problem, which in this particular case would be the system configuration that has no transmission outages instead of the one with the simultaneous imposition of transmission outages. This is because SINTO may exhibit the effect of Braess's paradox and create capacity that is not normally available under normal operating conditions. However, for other networks, the most restrictive case might have outages; in general, it will not be known ahead of time which is the most restrictive. Thus, a model is proposed that checks only two topologies, and uses the most restrictive one: the SINTO topology, and the NO topology (*i.e.*, letting $t = \{\text{NO}, \text{SINTO}\}$ in the Formulation 5.1).

This formulation approximately doubles the number of transmission system constraints compared to the SINTO model, yet it may be practical enough to be implemented. To reiterate the concept behind the NO-SINTO formulation is that if the normal operation of the system is more restrictive than the one that includes transmission outages (SINTO), then the awarded FTRs might be reduced to the value of the lesser of the two sets of transmission period constraints. This, however, may be more restrictive than SINTO but still not as restrictive as the multi-topology CHIMPO formulation because all the transmission system configurations are not modeled. Thus, the NO-SINTO formulation may be considered more of a heuristic than a complete solution to the problem since it trades off complete mitigation of Braess's paradox for computational performance.

Chapter 6

ERCOT Case Study: Models and Data

6.1 Objectives and scope of chapter

The case study described in Chapters 6 and 7 has two major objectives: investigate whether Braess's paradox and the SINTO model affect the FTR auction results of an actual power market, and verifying if the proposed NO-SINTO model outperforms the standard SINTO model. At present, the academic literature elucidates, for example, the nature of Braess's paradox and how, in theory, it impacts transmission investment [37] or how Braess's paradox can optimize the dispatch through transmission switching [14] utilizing small test circuits to prove their hypothesis. The present chapter investigates the practical effects and frequency of the paradox in real markets. This case study focuses ERCOT's 2014 CRR[1] monthly auction data to find empirical evidence for Braess's paradox. The auction software used in ERCOT CRR auctions, iHedge® FTR Market Simulator, is also used for this case study.

Thus, the first objective is to find empirical evidence of the paradox by comparing the CHIMPO and SINTO models from Chapters 3 and 5. The CHIMPO model is the reference case because it captures the actual chronological sequence of constraints from different transmission configurations derived from scheduled transmission outages. The standard SINTO approach approximates the CHIMPO SFT. By comparing the two models, one can see when non-coincident transmission outages can cause Braess's paradox. As explained in Chapter 4, modeling SINTO in congestion auctions can theoretically exacerbate the effects of Braess's paradox. Chapter 7 provides practical evidence that modeling SINTO does impact FTR auction results when Braess's paradox is active.

The second objective is to benchmark the performance of NO-SINTO and CHIMPO against the SINTO model using actual FTR auction data. The two performance criteria evaluated include the following: the ability to approximate the ideal but computationally expensive CHIMPO model, and computational performance for practical implementation in U.S. power markets. In Chapter 7, it is concluded that CHIMPO would be impractical for ERCOT due to prohibitive computational costs due to the number of topologies considered, but the NO-SINTO model can better reduce rev-

[1]A CRR (congestion revenue right) is a term that ERCOT uses for FTRs and is exactly the same financial instrument.

enue inadequacy due to Braess's paradox than the SINTO model at a reasonable computational expense.

The models developed in Chapters 3 and 5 are simplified representations of real power the market implementation of CRR auctions but can provide useful and relevant insight on market behavior and auction trends. The following sections focus on bridging the divide between theoretical models and practical implementation within ERCOT's CRR auction by discussing data, assumptions, processes and methodologies, with results presented in Chapter 7. In Section 6.2, the rationale for selecting ERCOT for the case study is explained. Section 6.3 explains CRR bidding details that require new auction functionality but adds additional complexity to ERCOT's actual CRR auction implementation. Section 6.4 describes ERCOT's auction process. Section 6.6 describes iHedge® FTR Market Simulator, which is used both by ERCOT and this case study. Section 6.7 describes the study case preparations for the SINTO, NO, NO-SINTO, CHIMPO formulations. This is followed in Section 6.8 by the case study assumptions, methodology, and procedure. The results of the case study are then analyzed in Chapter 7.

6.2 Market selection

In this section, the rationale is provided for selecting ERCOT as the power market to model for the case study. Figure 2.1 in Chapter 2 displays a map of the seven centralized power markets (Regional Transmission Organization/Independent System Operator) in the United States. As discussed in Chapter 2, all other non-centralized markets (shaded white) in the United States use bilateral markets and access to the transmission system is allocated via physical transmission rights. In contrast, each of the centralized market employs locational marginal prices and allocates FTRs. The decision of which market to choose for the case study was based on three criteria: auction data transparency, minimization of the impact of parallel flows from neighboring transmission systems, and market size. The ERCOT market was chosen primarily because of the availability and completeness of the Congestion Revenue Rights (CRR) auction data.

ERCOT provides all the necessary data to recreate the CRR auctions [145]. The data includes masked CRR auction bid and offer data, previously cleared FTR awards (called "Fixed bids"), the transmission grid model, a list of transmission contingencies, line ratings, interface definitions, aggregate and commercial nodes, a transmission line outages list, and mapping files. The description of this data is provided in Section 6.4. ERCOT masks the bid and offer data to keep the data confidential: preventing the determination of which market participant submitted the data. For the case study, market participant identification is not necessary since the analysis compares CRR auction result statistics for different formulations.

The second reason that the ERCOT market was selected is that it is a relatively isolated transmission system (see Figure 6.1). It is separated from the Eastern Interconnection by two direct current (DC) ties and from Mexico by three DC ties; as a result, parallel flows from adjoining transmission systems do not impact ERCOT transmission system flows. As explained in Section 2.3.2, inaccurate estimations of parallel flows in FTR auction model can also lead to revenue inadequacy by either underestimating the amount of parallel flow on lines in the prevailing flow direction or overestimating the amount of parallel flow on a line in the counter-flow direction.

The third reason is that ERCOT is a relatively large transmission system with many circuit configurations and is sufficiently extensive to serve as a proxy for transmission systems in other power markets.

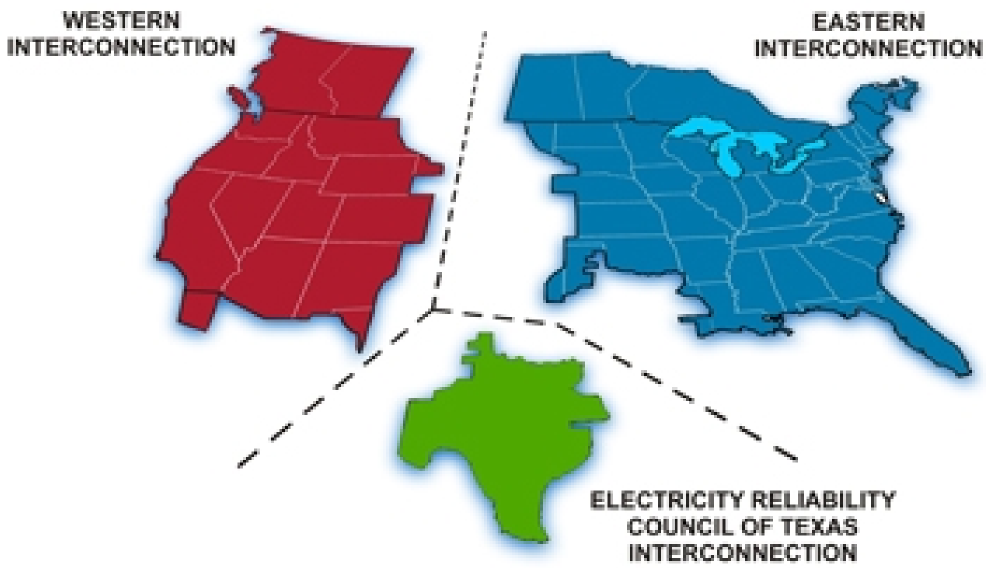


Figure 6.1: Map of U.S. interconnections [146]

6.3 ERCOT CRR auction complexities

This section discusses the usage of auction software for modeling multiple topologies. Further, this section provides necessary information to understand the case study data, terminology, model preparation, analysis, and results.

Nexant's precise formulation of their iHedge® CRR auction software package is not publicly available for proprietary reasons; however, for comprehension, this section summarizes the addition functionality Nexant includes but that is not depicted in the CHIMPO and NO-SINTO model formulations in Chapter 5. Moreover, a general CRR auction formulation is derived that includes the additional functionality to provide insight into how the additional functionality may be incorporated into those formulations. Although auction software and power systems operations are complex, the emergent behavior from the CHIMPO and NO-SINTO models show that better representation of network topology will reduce revenue inadequacy resulting from Braess's paradox, SINTO, and calendar-strip term sales, as described in Chapter 5. The actual CRR auction software, iHedge® FTR Market Simulator, can be configured to model multiple transmission configurations in its simultaneous feasibility test.[2] Despite this, as of end of 2014, all U.S. RTOs, including ERCOT, use SINTO models.

[2]Based on Nexant's staff, Joe Bright during iHedge training on April 2, 2014 at 111 Market Place, Baltimore Maryland 21202

Table 6.1: Sample (abridged) auction participants' auction bid data

Bid Index (s) CRR_ID	Bid Type	(Y_s^+) Source	(Y_s^-) Sink	H_s Type	(O_s) Hedge Type	(P_s) TimeOfUse	$F_s^{\max}$ MW	B_s BidPrice (US $)	Auction Participant (n) AccountHolder
20811677	CRR Bid	LPCCS_CT11	OLIN_OLING_1	BUY	OBL	24-Hours	10	0.02	XNRGP2
20811678	CRR Bid	HB_SOUTH	LZ_SOUTH	BUY	OBL	24-Hours	17	1.41	XNOBLE
20811679	CRR Bid	HB_NORTH	LZ_NORTH	BUY	OBL	24-Hours	1	0.26	XSESSW
20811680	CRR Bid	LZ_HOUSTON	HB_HOUSTON	BUY	OBL	24-Hours	5	-0.25	XNOBLE
20811681	CRR Bid	WHCCS_CT1_ST	HB_NORTH	BUY	OPT	24-Hours	2.5	0.07	XMETT3
20811682	CRR Bid	BYU_BYU_12	SL_PUN1	BUY	OPT	24-Hours	80	0.01	XSESSW
20811683	CRR Bid	CBY4_ALL	LZ_HOUSTON	BUY	OPT	Off-peak	10	0.01	XVITO2
20811684	CRR Bid	STP_STP_G2	DOWGEN_PUN1	BUY	OBL	Off-peak	1.5	0.13	XLQA2
20811685	CRR Bid	LZ_WEST	BULLCRK_1_2	SELL	OBL	Off-peak	2.6	3	XBJEN3
20811686	CRR Bid	INKS_INKS_G1	SD5SES_5	SELL	OBL	Off-peak	1	-0.5	XDARBY
20811687	CRR Bid	MIL_MILG1_2	PSA_PSA_G3	SELL	OBL	Off-peak	1.4	1.04	XBJEN3
20811688	CRR Bid	JCKCNTY2_CT3	LZ_WEST	SELL	OPT	Off-peak	0.5	1.32	XMETV2
20811689	CRR Bid	WFCOGEN_13	LZ_NORTH	SELL	OPT	PeakWD	9	0.71	XVITO2
20811690	CRR Bid	HB_SOUTH	LZ_SOUTH	BUY	OBL	PeakWE	0.4	6.5	XMETT3
...	...	...	...	...	...	...	...	...	...
$\lvert\mathcal{S}\rvert$	CRR Bid	HAYSEN3_4	LZ_LCRA	BUY	OBL	PeakWE	2.2	-0.24	XMETV2
20806733	Fixed Bid	WOO_WOODWRD1	WOO_WOODWRD2		OBL	PeakWE	0.2		XNRGP2
20800067	Fixed Bid	KEO_KEO_SM1	WOO_WOODWRD2		OPT	Off-peak	14.9		XVITO2
20805814	Fixed Bid	KEO_KEO_SM1	WOO_WOODWRD2		OPT	PeakWE	10		XSESSW
20803681	Fixed Bid	KEO_KEO_SM1	WOO_WOODWRD2		OPT	PeakWE	9		XNOBLE
20811325	Fixed Bid	FLCNS_UNIT1	WOO_WOODWRD2		OPT	PeakWD	18		XMETT3
17548149	Fixed Bid	WOO_WOODWRD1	WOO_WOODWRD2		OPT	PeakWD	6.8		XSESSW
17549534	Fixed Bid	OECCS_1	WOO_WOODWRD2		OPT	PeakWD	2		XDARBY
17559095	Fixed Bid	OECCS_1	WOO_WOODWRD2		OPT	Off-peak	19.9		XLQA2
17564831	Fixed Bid	KING_KINGNE	WOO_WOODWRD2		OPT	Off-peak	1		XBJEN3
17555771	Fixed Bid	KEO_KEO_SM1	WOO_WOODWRD2		OPT	PeakWE	9		XNOBLE
17564829	Fixed Bid	KEO_KEO_SM1	WOO_WOODWRD2		OPT	Off-peak	1		XBJEN3
17547583	Fixed Bid	IN_INDNENR_2	WOO_WOODWRD2		OPT	PeakWD	6.5		XMETV2
17547181	Fixed Bid	FLTCK_SSI	WOO_WOODWRD2		OPT	PeakWD	1.5		XMETV2
17547744	Fixed Bid	CALLAHA_WND1	WOO_WOODWRD2		OPT	PeakWD	9.3		XMETT3
...	...	...	...	...	...	...	...	...	...
$\lvert\mathcal{S}\rvert$	Fixed Bid	KEO_KEO_SM1	WOO_WOODWRD2		OPT	Off-peak	3		XVITO2

6.3.1 Bid data structure

Typically, a list of auction participants $n \in \mathcal{N}$ submit their bids to the RTO. The RTO receives bid data as shown in Table 6.1 [145]. Each bid $s \in \mathcal{S}$ can have several characteristics: Bid or offer type (H_s), hedge type (O_s), time-of-use (P_s), fixed bid quantity ($F_s^{\max}$), and an associated auction participant n. The variables will be described on an as-needed basis in subsequent sections. We define subsets of $\mathcal{S}$ with superscripts to describe the relevant characteristics. For example, $\mathcal{S}^{\text{Buy}}$ denotes the set of all Buy bids. In this particular case, given a set of bid or offer type

$H_s \in \{\text{Buy}, \text{Sell}\}$, $\forall s \in \mathcal{S}$, the set $\mathcal{S}^{\text{Buy}} \subseteq \mathcal{S}$ can be defined as $\mathcal{S}^{\text{Buy}} = \{s | H_s = \text{Buy}\}$.

6.3.2 Settlement points

In ERCOT, electricity trade is accomplished between Settlement Price Points (SPPs[3]), rather than electric buses. It is possible to transact each SPP as a source or a sink for each bid s.

Let $\mathcal{Y}$ denote the set of SPPs, where each SPP may include one or more buses. To track SPPs to buses, we designate a set $\mathcal{I}_y^{\text{SPP}}$ that maps all the buses i that belong in SPP $y \in \mathcal{Y}$. For example, if the SPP OECCS_1 included buses 1, 2, and 3, then $\mathcal{I}_{\text{OECCS\_1}}^{\text{SPP}} = \{1, 2, 3\}$.

The advantages of aggregating multiple buses into SPPs are as follows:

- More descriptive bus names: for example, in ERCOT, LZ_ precedes a load zone SPP,[4] RN_ precedes a resource SPP, HB_ precedes a Hub SPP, etc.
- It allows the definition of aggregated points: Hubs and Zones
- It limits the number of bid points - not every bus is a bid point - and therefore defines more precisely where participants can bid. In ERCOT, the sources and sinks include generator points, Hubs, and Zones.

[3] In other RTOs, SPPs are called Commercial Pricing Nodes (CPNodes) that can be either Pricing Nodes (PNodes) or Aggregate Pricing Nodes (APNodes).

[4] A load zone is a collection of buses representing consumers. In ERCOT, the load zones are historical zones established using cluster analysis to define a set of commercially significant constraints in their zonal (not LMP) market. In other power markets, the load zones represent historical utility service areas.

- Naming consistency: bus names are designated by transmission owner and transmission owners have their own abbreviations for bus names.

Settlement point definitions

An SPP can either have a one-to-one correspondence with an electrical bus or is an aggregate that includes a group of buses that uses a simple average or weighted average to distribute a power injection or withdrawal as determined by the ERCOT's stakeholders. These weighting factors also are used to aggregate the LMPs for price determination.

When an FTR bid s is awarded, the delivered power is estimated to begin at a source and end at a sink, which may be distributed over several buses. Each bid s designates a source SPP $Y_s^+ \in \mathcal{Y}$ and a sink SPP $Y_s^- \in \mathcal{Y}$. Referring back to Table 6.1, the bid s=17549534 injects at SPP Y_s^+ = OECCS_1 and withdraws from SPP Y_s^- = WOO_WOODWRD2. Let $\mathcal{I}_y^{\text{SPP}}$ designate the set of buses associated with SPP $y \in \mathcal{Y}$. Then, the power injected into a source Y_s^+ and may be distributed over a set of of buses $\mathcal{I}_y^{\text{SPP}}$ for $y = Y_s^+$. Similarly, the power withdrawn from a sink Y_s^- due to bid s may be distributed over the set of buses $\mathcal{I}_y^{\text{SPP}}$ for $y = Y_s^+$. For example, if the SPP OECCS_1 were associated to buses 1 and 2, and the SPP WOO_WOODWRD2 were associated to buses 3, 4, and 5, then $\mathcal{I}_{\text{OECCS\_1}}^{\text{SPP}} = \{1, 2\}$ and $\mathcal{I}_{\text{WOO\_WOODWRD2}}^{\text{SPP}} = \{3, 4, 5\}$. Thus, it is possible to map each bid to the affected by a power injection or withdrawal.

In order to track the sensitivity of an SPP injection or withdrawal on the power flows into each bus, we define a matrix $\boldsymbol{M}$ that describes the per-unit power flow distribution due to each bid s. A positive value designates an injection at bus i, and a negative value designates power withdrawal at bus i. Each column s of $\boldsymbol{M}$, denoted as $\boldsymbol{M}_s$, has the following properties: its sum is zero and its ℓ_1-norm ≤ 2. Thus, the power injected into bus i can be calculated as $\boldsymbol{M}\boldsymbol{f}$. The injection matrix $\boldsymbol{M}$ is further described in [12].

The values of $\boldsymbol{M}$ depends on the type of SPP (*i.e.*, resource, hub or zone) at the source and at the sink, but can be calculated as the sum of the effects from injections $\boldsymbol{M}^+$ and withdrawals $\boldsymbol{M}^-$. Thus, $\boldsymbol{M} = \boldsymbol{M}^+ - \boldsymbol{M}^-$, where, the values M_{is}^+ and M_{is}^- are calculated $\forall i \in \mathcal{I}_y^{\text{SPP}}, y = Y_s^+$ and $\forall i \in \mathcal{I}_y^{\text{SPP}}, y = Y_s^-$, respectively, below.

- **Resource**: If the bid s is sourced from a single generator at bus i and sinked at a bus j, then $M_{is}^+ = 1$ and $M_{js}^- = 1$. For example, if $\boldsymbol{M}_s = (1, -1, 0, \ldots, 0)$, then all power injected into the grid due to bid s begins at bus 1 (source) and ends at bus 2 (sink).

- **Hub**: For an aggregate bid such as a hub, a bid injection at the source is accomplished by distributing the bid proportionally across the buses that define that hub. If the bid s is sourced from or delivered to the hub containing bus i (defined as all 345 kV buses, according to ERCOT), then $M_{is}^+ = \dfrac{1}{|\mathcal{I}_y^{\text{SPP}}|}$ and $M_{is}^- = \dfrac{1}{|\mathcal{I}_y^{\text{SPP}}|}$. Using the example earlier in this section, when a bid s injects at SPP OECCS_1 and withdraws from WOO_WOODWRD2, then $\boldsymbol{M}_s =$

$\left(\frac{1}{2}, \frac{1}{2}, -\frac{1}{3}, -\frac{1}{3}, -\frac{1}{3}, 0, \ldots, 0,\right)$, power is injected evenly from a hub containing buses 1 and 2, and withdrawn evenly from a hub containing buses 3, 4, and 5.

- **Zone**: A withdrawal at a load zone sink is accomplished through a proportional distribution based on the weights of the load L_i at each bus. If the bid s is sourced from or delivered to a zone containing bus i, then $M_{is} = \frac{L_i}{\sum_{j \in \mathcal{I}_y^{\mathrm{SPP}}}}$. For example, power were injected from bus 3, and withdrawn from a load zone WOO_WOODWRD2 containing buses 1 and 2, then $\boldsymbol{M}_s = \left(-\frac{L_1}{L_1+L_2}, -\frac{L_2}{L_1+L_2}, 1, 0, \ldots, 0\right)$.

By following the above rules, it is possible to generate the $\boldsymbol{M}$ matrix in order to estimate the resultant power flows from each accepted bid.

6.3.3 Multi-period auctions

One of the complexities in the ERCOT's CRR auction implementation is that the auction is designed to clear multiple time-of-use block CRR products to accommodate how power is traded in the bilateral market.[5] The term-based products are the following: 24-hour (*i.e.*, around-the-clock), peak-weekday, off-peak and, peak-weekend.

Figure 6.2 displays the hours included in each product. For example, the peak-weekday calendar-strip includes the sixteen hours from 0700 to 2200, from Monday

[5] "The utilities operate in wholesale markets governed by contracts between and among the participants in those markets – contracts that are regulated by FERC. Because of this characteristic, these wholesale markets have become known as 'bilateral markets' even though it is a bit of a misnomer, as bilateral contracts also are a significant part of centralized markets." Source: [147]

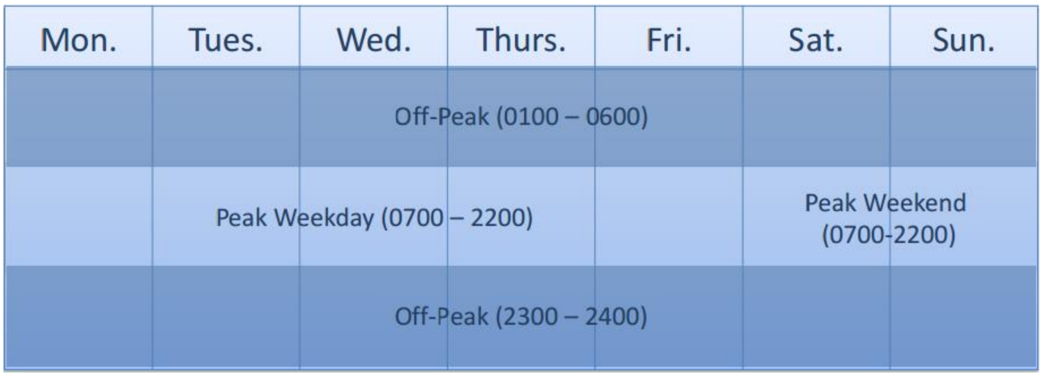


Figure 6.2: ERCOT TOU diagram [148]

through Friday, for the entire month. For a non-leap year February (28 days), this would amount to a total of $W_s = 320$ hours, where W_s is a parameter that weighs bids to account for the number of hours in an FTR product.[6] 24-hour bids are not displayed in the chart but intuitively includes all hours in a CRR auction period – in this case all the hours in a month. In ERCOT, the auction software, iHedge®, is configured to accommodate multi-period products.[7]

In order to accommodate multi-period bids, we create a set of periods $\mathcal{P} = \{\text{PeakWD}, \text{PeakWE}, \text{Offpeak}\}$, which denotes peak weekday, peak weekend, and off-peak periods, respectively. We modify the SINTO FTR model (Formulation 3.2) as follows. Note that the following conditions apply to all equations where appropriate: $\forall i \in \mathcal{I}, \forall j \in \mathcal{I}, \forall p \in \mathcal{P}, \forall s \in \mathcal{S}, \forall s' \in \mathcal{S}$.

[6]Note that while the weight is proportional to the number of hours, that W_s is a unitless variable.

[7]This multi-period functionality is also used in ERCOT's semi-annual CRR auction where a calendar-strip can include any combination of one-month increments up to six-month and time-of-use period bids.

Formulation 6.1: CRR auction formulation with TOU and multi-period FTRs

$$\max_{\substack{\boldsymbol{f},\boldsymbol{q}^{\text{Line}},\\ \boldsymbol{q}^{\text{Bus}},\boldsymbol{\theta}}} \quad \sum_{s\in\mathcal{S}} W_s C_s^{\text{Bid}} f_s \tag{6.1a}$$

Subject to:

$$\sum_{s\in\mathcal{S}} M_{isp} f_s = q_{ip}^{\text{Bus}} \tag{6.1b}$$

$$0 \le f_s \le F_s^{\max} \tag{6.1c}$$

$$f_{s'} = f_s \qquad s > s' \wedge s' \in \mathcal{S}_s^{24\text{hr}} \tag{6.1d}$$

$$Q_{ij}^{\min} \le q_{ijp}^{\text{Line}} \le Q_{ij}^{\max} \qquad j \in \mathcal{I}_i^{\text{Conn}}, j > i \tag{6.1e}$$

$$\sum_{\substack{j\in\mathcal{I}_i^{\text{Conn}}\\ j<i}} -q_{ijp}^{\text{Line}} + \sum_{\substack{j\in\mathcal{I}_i^{\text{Conn}}\\ j>i}} q_{ijp}^{\text{Line}} + q_{ip}^{\text{Bus}} = 0 \tag{6.1f}$$

$$B_{ij}\left(\theta_{ip} - \theta_{jp}\right) = q_{ijp}^{\text{Line}} \qquad \forall j \in \mathcal{I}_i^{\text{Conn}}, j > i \tag{6.1g}$$

where, in (6.1a), the objective function includes W_s, which weighs each bid by the number of hours corresponding to each bid s. In (6.1b), the $\boldsymbol{M}$ matrix is modified to include TOU periods $p \in \mathcal{P}$, such that each bid s corresponds to buses i and a single period p. Similarly, $\boldsymbol{q}$ has also gained a dimension p in (6.1e)-(6.1g) to account for flows in different time periods. Equation (6.1d) accounts for 24-hour bids (bids that apply to all time periods) by forcing the bid quantities f_s to be equal for each time period p. This is achieved by using a set $\mathcal{S}_s^{24\text{hr}}$ that maps all corresponding 24-hour bids to s. For example, if bids 1, 4, and 7 correspond to the peak-weekday, peak-weekend, and off-peak components of a single 24-bid, then $\mathcal{S}_1^{24\text{hr}} = \{4, 7\}$. Thus, each 24-hour bid requires three decision variables, all with the same value.

6.3.4 Expanded model to include fixed bids and CRR offers

In this section, we combine and adapt the multi-period CRR auction and multi-topology models from formulations (5.1) and (6.1) to account for pre-existing CRR awards and for offers to sell FTRs. The former is achieved by constraining pre-existing awards or allocations to fixed values $F_s^{\max}$, where the set of pre-existing awards belong to the set $\mathcal{S}^{\text{Fixed}} \subseteq \mathcal{S}$. It is important to account for pre-existing awards because they impact transmission system capacity.

The model also allows the sales of FTRs, achieved by defining a set of buy bids $\mathcal{S}^{\text{Buy}} \subseteq \mathcal{S}$ and sell bids $\mathcal{S}^{\text{Sell}} \subseteq \mathcal{S}$. Each s can either a bid to buy FTRs, or an offer to sell FTRs. The sets $\mathcal{S}^{\text{Buy}}$ and $\mathcal{S}^{\text{Sell}}$ represent buy and sell bids, respectively, and are partitions[8] of $\mathcal{S}$. These sets can be defined as follows: $\mathcal{S}^{\text{Buy}} = \{s|H_s = \text{Buy}\}$ and $\mathcal{S}^{\text{Sell}} = \{s|H_s = \text{Sell}\}$.

When CRRs are acquired in previous auctions (Fixed Bids), they may be offered for sale in the monthly CRR auction. The offer price may be positive or negative. A negative price denotes that the CRR holder who is offering their CRR into the auction is willing to pay a buyer in order to discard the risk associated with the CRR. In a CRR Obligation, if the direction of congestion is opposite to the direction of the CRR, the CRR holder pays the RTO the difference between the (higher) LMP at the source location and the (lower) LMP at the sink location multiplied by the quantity of CRRs on that path. In this case, the holder perceives that they are financially exposed because of the downside risk of negative cash flows. Conversely, if the congestion is predicted to be in the same direction as the CRR, the CRR has a positive value (or cash flow). Thus, the holder will want to be compensated for selling the CRR.

The expanded model is as follows. Note that the following conditions apply to all equations where appropriate: $\forall i \in \mathcal{I}, \forall j \in \mathcal{I}, \forall p \in \mathcal{P}, \forall s \in \mathcal{S}$ and $\forall s' \in \mathcal{S}$. In addition, we also consider all topologies t relevant to the evaluated model (*e.g.*, $\forall t \in \mathcal{T}^{\text{CHIMPO}}$ for the CHIMPO model).

Formulation 6.2: CRR auction formulation with TOU, multi-period, Offers, fixed bids and multi-topology

$$\max_{\substack{\boldsymbol{f},\boldsymbol{q}^{\text{Line}},\\ \boldsymbol{q}^{\text{Bus}},\boldsymbol{\theta}}} \sum_{s\in\mathcal{S}^{\text{Buy}}} W_s C_s^{\text{Bid}} f_s - \sum_{s\in\mathcal{S}^{\text{Sell}}} W_s C_s^{\text{Bid}} f_s \tag{6.2a}$$

Subject to:

$$\sum_{s\in\mathcal{S}^{\text{Buy}}} M_{isp} f_s - \sum_{s\in\mathcal{S}^{\text{Sell}}} M_{isp} f_s = q_{ip}^{\text{Bus}} \tag{6.2b}$$

$$f_s = F_s^{\max} \qquad \forall s \in \mathcal{S}^{\text{Fixed}} \tag{6.2c}$$

$$0 \le f_s \le F_s^{\max} \qquad \forall s \notin \mathcal{S}^{\text{Fixed}} \tag{6.2d}$$

$$f_{s'} = f_s \qquad s > s' \wedge s' \in \mathcal{S}_s^{\text{24hr}} \tag{6.2e}$$

$$Q_{ij}^{\min} \le q_{ijpt}^{\text{Line}} \le Q_{ij}^{\max} \qquad j \in \mathcal{I}_i^{\text{Conn}}, j > i \tag{6.2f}$$

$$\sum_{\substack{j\in\mathcal{I}_i^{\text{Conn}}\\ j<i}} -q_{ijpt}^{\text{Line}} + \sum_{\substack{j\in\mathcal{I}_i^{\text{Conn}}\\ j>i}} q_{ijpt}^{\text{Line}} + q_{ip}^{\text{Bus}} = 0 \tag{6.2g}$$

$$B_{ijpt}\left(\theta_{ipt} - \theta_{jpt}\right) = q_{ijpt}^{\text{Line}} \qquad j \in \mathcal{I}_i^{\text{Conn}}, j > i \tag{6.2h}$$

where (6.2c) and (6.2d) set the feasible space for fixed and flexible bid, respectively.

Equation (6.2g) has been modified to separate injections into and withdrawals from the grid at bus i during period p for topology t.

6.3.5 CRR Options

A auction participant may bid for FTR Options or Obligations, depending on how they want to hedge their bid. Thus, from Table 6.1, based on the hedge type $O_s \in \{\mathrm{Obl}, \mathrm{Opt}\}$, we define the sets of FTR Obligations (Obl) bids and Options (Opt) bids as $\mathcal{S}^{\mathrm{Obl}} = \{s | O_s = \mathrm{Obl}\}$ and $\mathcal{S}^{\mathrm{Opt}} = \{s | O_s = \mathrm{Opt}\}$, respectively, where these are partitions of $\mathcal{S}$.

Another important functionality beyond those already discussed is that ERCOT provides two hedging alternatives by providing two types of CRRs – Obligations and Options. All CRR are directional where the bidder must designate a path from a source node and a sink node which is modeled as a point of power injection and withdrawal respectively in the auction's transmission model. CRR Obligations pay the holder if the direction of CRR is in the direction of congestion. However, if the direction of congestion is in the opposite direction of the CRR, the CRR holder is charged the LMP difference. Similar to a CRR Obligations, CRR Options pay the holder if the direction of the CRR Option is in the same direction as the congestion, but unlike CRR Obligations, CRR Options do not charge the holder if the congestion direction is in the opposite direction.

Figure 6.3 provides a diagram depicting CRR Obligation and CRR Option payouts. On the x-axis, $LMP_2 - LMP_1$ is the difference between LMP_2 the LMP at the sink and LMP_1 the LMP at the source. The y-axis depicts the payoff. Payoffs above the x-axis are positive and negative when it is below. A negative payoff indicates a situation where a payment is made from the FTR owner to the RTO. The blue dashed line illustrates the FTR Option, and the red dotted line illustrates the FTR Obligation. The value at the intersection for both axes is equal to zero. The main difference between the two instruments is that when the LMP difference is negative the payoff value for the FTR Obligation is negative whereas for the FTR Option it is zero.

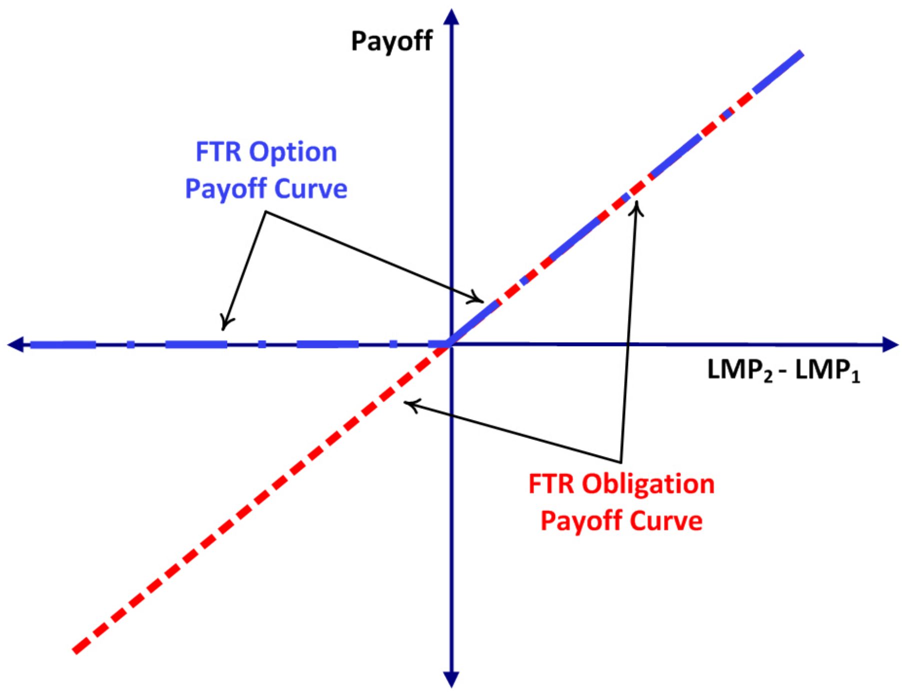


Figure 6.3: Payoff curves for FTRs as Options or Obligations [149]

From an auction modeling perspective, CRR Obligations allow the flow from other

CRR Obligations in the opposite direction to offset each other such that the flow on the line is equal to the difference of the flows (net flow). An unlimited quantity of CRR Obligations can be sold as long as the net flow is equal to or below the line limit. Revenue adequacy is maintained although an unlimited amount of CRR Obligations may be sold because the CRR holders of offsetting CRR Obligations are obliged to pay when the direction of the congestion is in the opposite direction of their CRR. Theoretically, the total CRR Obligation charges and the congestion rents are enough to pay the CRR Obligation holders.

In contrast, since CRR Options do not charge the holders when congestion is in the opposite direction as the CRR, there are no additional funds collected from these instruments to cover any additional payments to CRR in the forward direction thus CRR Options are modeled differently. CRR Options are modeled such that they do not count offsetting flows (counter-flows) like CRR Obligations that enable more CRRs in the opposite direction to be awarded. While the flow calculations differ between Obligations and Options, Braess's paradox impact Options as well.

In [37,150–157] and in the Braess's paradox example presented in Chapter 4 of this thesis, a single flow is used to demonstrate the impact of Braess's paradox that is not predicated on counter-flows therefore Braess's paradox does not require counter-flow as a necessary condition for it to occur and impact CRR Options.

6.3.6 Credit and budget constraints

The credit and budget constraints are similarly formulated but serve two different purposes. The credit constraint is imposed by ERCOT (RTO/ISO) based on the credit exposure ERCOT calculates for the auction participant $n \in \mathcal{N}$, where $\mathcal{N}$ denotes the set of auction participants [148, 158, 159]. The budget constraint is a self-imposed constraint that enables bidder (auction participant) to cap the total amount that they pay for all the bids and offers s if they clear the auction. The set $\mathcal{S}_n^{\text{Bid}}$ maps all the bids and offers associated to bidder n. For example, in Table 6.1, bids 17547583 and 17547181 were submitted by participant n=XMETV2, thus $\mathcal{S}_{\text{XMETV2}}^{\text{Bid}} = \{17547583, 17547181\}$. $\mathcal{S}_n^{\text{Bid}}, \forall n \in \mathcal{N}$ are partitions of $\mathcal{S}$.

In the following constraint, the sum of costs must remain below the budget/credit Z_n for each auction participant $n \in \mathcal{N}$:

$$\sum_{s \in \mathcal{S}^{\text{Opt}}} \max(0, C_s^{\text{Bid}}) f_s - \sum_{\substack{s \in \mathcal{S}^{\text{Sell}} \\ s \in \mathcal{S}^{Obl}}} \min(0, C_s^{\text{Bid}}) f_s + \sum_{\substack{s \in \mathcal{S}^{\text{Buy}} \\ s \in \mathcal{S}^{Obl}}} (\phi |C_s^{\text{Bid}}| + \eta) f_s \leq Z_n, \quad \forall s \in \mathcal{S}_n^{\text{Bid}}$$

where, on the left-hand side, the first term represents the financial exposure for CRR Options buy awards. Since selling CRR Options to ERCOT creates zero financial exposure it does not need to be reflected in the constraint. The second term describes CRR Obligation offers exposure where the CRR Obligation offers clear the auction with a negative price such that money is owed to ERCOT. The last term describes CRR Obligations buys in either direction and guarantees that a bidder cannot systematically profit from holding CRR Obligations in both directions. ϕ and η are parameters defined and published by the CRR market operator every month to calculate the variable and constant component of the exposure of Obligations, respectively, due to bid prices C_s^{Bid} [158]. Note that $\eta > 0$.

The value of Z_n is the lesser value between the available credit (tracked and calculated by ERCOT for each market participant n), and the participant's self-imposed budgetary constraint [148, 159].[9]

6.3.7 Generic constraints

ERCOT defines a generic constraint as a "transmission constraint made up of one or more grouped transmission elements that is used to constrain flow between geographic areas of ERCOT for the purpose of managing stability, voltage, and other constraints that cannot otherwise be modeled directly in ERCOTs power flow and contingency analysis applications" [161].

Each geographic area, called an interface v, has a maximum quantity of power than can be transferred, known as the interface limit Q_v^{Int}. Let $v \in \mathcal{V}$ denote the set of interfaces. Further, let $\mathcal{L}_v^{\text{Int}}$ be a set of lines, denoted by tuples (i,j), contained in the interface v. Note that a generic constraint can be (and often is) directional, where the interface limit Q_v^{Int} may be different in either direction or may not be defined in

[9] ERCOT has two levels of credit constraints: one for the auction participant or the counterparty, and the other for the account holder since an account holder can participate in multiple markets and may have broader credit constraints [160].

one of the directions.

The notation is read as follows: A^{PTDF}_{ijst}, is the per-unit power transfer distribution factor on the line from bus (or buses) i to bus (or buses) j from a power transfer due to bid s for topology t.

The equation below is an example of the interface constraint:

$$\sum_{(i,j)\in\mathcal{L}^{\text{Int}}_v} \big(q^{\text{Line}}_{ijpt} + \sum_{\substack{s\in\mathcal{S}^{Opt}\\ P_s=p}} \max(0, A^{\text{PTDF}}_{ijst}) f_s\big) \leq Q^{\text{Int}}_v, \quad \forall p \in \mathcal{P}, \forall t \in \mathcal{T}, \forall v \in \mathcal{V}$$

where, as described earlier, P_s is the time-of-use period associated with bid s.

Formulation 6.3, as follows, includes all the functionality discussed thus far: CRR offers, Fixed Bids, TOU, settlement points and budget constraints, generic constraints and CRR Options is modified using FTR Options formulation [162] [96]. Note that the following conditions apply to all equations where appropriate: $\forall i \in \mathcal{I}, \forall j \in \mathcal{I}, \forall p \in \mathcal{P}, \forall s \in \mathcal{S}, \forall s' \in \mathcal{S}, \forall v \in \mathcal{V}, \forall n \in \mathcal{N}$. In addition, we also consider all topologies t relevant to the evaluated model (*e.g.*, $\forall t \in \mathcal{T}^{\text{CHIMPO}}$ for the CHIMPO model)

Formulation 6.3: CRR auction formulation with TOU, multi-period, buys and sells, fixed bids, multi-topology, Options, credit and budget constraints, generic constraints

$$\max_{\substack{\boldsymbol{f},\boldsymbol{q}^{\text{Line}},\\ \boldsymbol{q}^{\text{Bus}},\boldsymbol{\theta}}} \quad \sum_{s\in\mathcal{S}^{\text{Buy}}} W_s C_s^{\text{Bid}} f_s - \sum_{s\in\mathcal{S}^{\text{Sell}}} W_s C_s^{\text{Bid}} f_s \tag{6.3a}$$

Subject to:

$$\sum_{s\in\mathcal{S}^{\text{Buy}}} M_{isp} f_s - \sum_{s\in\mathcal{S}^{\text{Sell}}} M_{isp} f_s = q_{ip}^{\text{Bus}} \tag{6.3b}$$

$$f_s = F_s^{\max} \qquad \forall s \in \mathcal{S}^{\text{Fixed}} \tag{6.3c}$$

$$0 \leq f_s \leq F_s^{\max} \qquad \forall s \notin \mathcal{S}^{\text{Fixed}} \tag{6.3d}$$

$$f_{s'} = f_s \qquad s > s' \wedge s' \in \mathcal{S}_s^{\text{24hr}} \tag{6.3e}$$

$$\sum_{\substack{j\in\mathcal{I}_i^{\text{Conn}}\\ j<i}} -q_{ijpt}^{\text{Line}} + \sum_{\substack{j\in\mathcal{I}_i^{\text{Conn}}\\ j>i}} q_{ijpt}^{\text{Line}} + q_{ip}^{\text{Bus}} = 0 \tag{6.3f}$$

$$B_{ijpt}\left(\theta_{ipt} - \theta_{jpt}\right) = q_{ijpt}^{\text{Line}} \qquad j \in \mathcal{I}_i^{\text{Conn}}, j > i \tag{6.3g}$$

$$\sum_{s\in\mathcal{S}^{\text{Opt}}} \max(0, C_s^{\text{Bid}}) f_s - \sum_{\substack{s\in\mathcal{S}^{\text{Sell}}\\ s\in\mathcal{S}^{Obl}}} \min(0, C_s^{\text{Bid}}) f_s + \sum_{\substack{s\in\mathcal{S}^{\text{Buy}}\\ s\in\mathcal{S}^{Obl}}} (\phi|C_s^{\text{Bid}}| + \eta) f_s \leq Z_n \qquad \forall s \in \mathcal{S}_n^{\text{Bid}} \tag{6.3h}$$

$$q_{ijpt}^{\text{Line}} + \sum_{\substack{s\in\mathcal{S}^{\text{Opt}}\\ P_s=p}} \max(0, A_{ijst}^{\text{PTDF}}) f_s \leq Q_{ij}^{\max} \qquad j \in \mathcal{I}_i^{\text{Conn}}, j > i \tag{6.3i}$$

$$-q_{ijpt}^{\text{Line}} + \sum_{\substack{s\in\mathcal{S}^{\text{Opt}}\\ P_s=p}} \max(0, -A_{ijst}^{\text{PTDF}}) f_s \leq Q_{ij}^{\max} \qquad j \in \mathcal{I}_i^{\text{Conn}}, j > i \tag{6.3j}$$

$$\sum_{(i,j)\in\mathcal{L}_v^{\text{Int}}} \big(q_{ijpt}^{\text{Line}} + \sum_{\substack{s\in\mathcal{S}^{\text{Opt}}\\ P_s=p}} \max(0, A_{ijst}^{\text{PTDF}}) f_s\big) \leq Q_v^{\text{Int}} \tag{6.3k}$$

6.3.8 Contingency analysis

Contingency analysis is a reliability criterion determined by North American Electric Reliability Organization (NERC) for system security. System security is defined by NERC as the ability of the bulk power system to withstand sudden and expected disturbances.[10] Contingency analysis accomplishes this function. NERC defines a contingency as "the unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch or other electrical element." Power systems in the United States are operated to meet NERC's reliability standards and to do so perform contingency analysis.[11] A convention used in discussing contingencies is the $n - x$ notation, for example, $n - 0$ is the system without contingencies and $n-1$ means that single contingencies are considered. A single contingency may include multiple elements (equipment) that "are physically or electrically linked and fail together as one." Most transmission lines have two limits called the normal and emergency short-term ratings. The normal rating is a 24-hour continuous rating whereas emergency ratings have a duration of less than 24-hours that requires the system operator to re-dispatch the system to bring the line flows back under the normal rating within a period required by the NERC's operating standards. These ratings are determined by the transmission owners in compliance with NERC's Standard FAC-008-3 Facility Ratings. Under normal operating conditions $(n - 0)$ the normal ratings determine the line flow limits while under contingencies $(n - 1)$ the emergency short-term limits are used.

[10] NERC's complete definition: system security as the ability of the Bulk-Power System to withstand sudden, unexpected disturbances, such as short circuits or unanticipated loss of system elements due to natural causes or caused by manmade physical or cyber attacks.

[11] NERC Standard TOP-004-2 Transmission Operations: Purpose: To ensure that the transmission system is operated so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single Contingency and specified multiple Contingencies.

Contingency analysis calculates the flows on the transmission system for every defined contingency to determine if any equipment is overloaded under any contingency. This analysis is a computationally intense iterative process that determines the power system's state after each contingency. Operating the power system to maintain reliability under contingencies reduces overall power system capacity because transmission equipment flows must be reduced to absorb the potential redistributed flows from elements that go on outage in a contingency. RTOs use a Security Constrained Economic Dispatch (SCED) that minimizes system cost and constrains the generation dispatch to keep flows on the transmission system equal to or below the transmission system equipment limits both without $(n-0)$ and with contingencies $(n-1)$. If contingencies are disregarded in CRR auctions, then too many may be sold, resulting in a risk of revenue inadequacy. This critical functionality adds complexity to ERCOT's commercial CRR auction implementation not shown in the formulations presented earlier in this thesis and not typically shown in many academic models. Formulation 6.4 shows how the above formulations are modified to include contingency analysis in the simultaneous feasibility test and includes all the additional functionality covered above in Sections from 6.3.2 to 6.3.5. For simplification, the formulation is presented fully utilizing linear approximation sensitivity factors (PTDFs and OTDFs) instead of the B-θ formulation defined above that calculates flows based on phase angle differences between adjacent buses. Outage Transfer Distribution Factors (OTDF) are similar to PTDFs as described in Section 6.3.5 except that is calculated after a contingency. In other words, it is the PTDF after a contingency. The notation is read as follows: A_{ijstc}^{OTDF}, is the outage transfer distribution factor on the line from bus (or buses) i to bus (or buses) j from a power transfer due to bid s for contingency c of topology t.

The expanded model that includes PTDF and budget limits is as follows. Note that the following conditions apply to all equations where appropriate: $\forall i \in \mathcal{I}, \forall j \in \mathcal{I}, \forall p \in \mathcal{P}, \forall s \in \mathcal{S}, \forall s' \in \mathcal{S}, \forall v \in \mathcal{V}, \forall n \in \mathcal{N}, \forall c \in \mathcal{C}$. In addition, all topologies t relevant to the evaluated model (*e.g.*, $\forall t \in \mathcal{T}^{\text{CHIMPO}}$ for the CHIMPO model) are considered.

Formulation 6.4: CRR auction formulation with all functionality

$$\max_{\boldsymbol{f}} \quad \sum_{s\in\mathcal{S}^{\text{Buy}}} W_s C_s^{\text{Bid}} f_s - \sum_{s\in\mathcal{S}^{\text{Sell}}} W_s C_s^{\text{Bid}} f_s \tag{6.4a}$$

Subject to:

$$f_s = F_s^{\max} \qquad \forall s \in \mathcal{S}^{\text{Fixed}} \tag{6.4b}$$

$$0 \le f_s \le F_s^{\max} \qquad \forall s \notin \mathcal{S}^{\text{Fixed}} \tag{6.4c}$$

$$f_{s'} = f_s \qquad s > s' \wedge s' \in \mathcal{S}_s^{24\text{hr}} \tag{6.4d}$$

$$\sum_{s\in\mathcal{S}^{\text{Opt}}} \max(0, C_s^{\text{Bid}}) f_s - \sum_{\substack{s\in\mathcal{S}^{\text{Sell}}\\ s\in\mathcal{S}^{Obl}}} \min(0, C_s^{\text{Bid}}) f_s + \sum_{\substack{s\in\mathcal{S}^{\text{Buy}}\\ s\in\mathcal{S}^{Obl}}} (\phi|C_s^{\text{Bid}}| + \eta) f_s \le Z_n \qquad \forall s \in \mathcal{S}_n^{\text{Bid}} \tag{6.4e}$$

$$\sum_{\substack{s\in\mathcal{S}^{\text{Obl}}\\ P_s=p}} A_{ijst}^{\text{PTDF}} f_s + \sum_{\substack{s\in\mathcal{S}^{\text{Opt}}\\ P_s=p}} \max(0, A_{ijst}^{\text{PTDF}}) f_s \le Q_{ij}^{\max} \qquad j \in \mathcal{I}_i^{\text{Conn}}, j > i \tag{6.4f}$$

$$\sum_{\substack{s\in\mathcal{S}^{\text{Obl}}\\ P_s=p}} -A_{ijst}^{\text{PTDF}} f_s + \sum_{\substack{s\in\mathcal{S}^{\text{Opt}}\\ P_s=p}} \max(0, -A_{ijst}^{\text{PTDF}}) f_s \le Q_{ij}^{\max} \qquad j \in \mathcal{I}_i^{\text{Conn}}, j > i \tag{6.4g}$$

$$\sum_{\substack{s\in\mathcal{S}^{\text{Obl}}\\ P_s=p}} A_{ijstc}^{\text{OTDF}} f_s + \sum_{\substack{s\in\mathcal{S}^{\text{Opt}}\\ P_s=p}} \max(0, A_{ijstc}^{\text{OTDF}}) f_s \le Q_{ij}^{\text{emer}} \qquad j \in \mathcal{I}_i^{\text{Conn}}, j > i \tag{6.4h}$$

$$\sum_{\substack{s\in\mathcal{S}^{\text{Obl}}\\ P_s=p}} -A_{ijstc}^{\text{OTDF}} f_s + \sum_{\substack{s\in\mathcal{S}^{\text{Opt}}\\ P_s=p}} \max(0, -A_{ijstc}^{\text{OTDF}}) f_s \le Q_{ij}^{\text{emer}} \qquad j \in \mathcal{I}_i^{\text{Conn}}, j > i \tag{6.4i}$$

$$\sum_{(i,j)\in\mathcal{L}_v^{\text{Int}}} \Big(\sum_{\substack{s\in\mathcal{S}^{\text{Obl}}\\ P_s=p}} A_{ijst}^{\text{PTDF}} f_s + \sum_{s\in\mathcal{S}^{Opt}} \max(0, A_{ijst}^{\text{PTDF}}) f_s \Big) \le Q_v^{\text{Int}} \tag{6.4j}$$

6.4 ERCOT CRR auction process

ERCOT market participants acquire CRRs through a series of auctions conducted monthly and semi-annually. The monthly auction provides bidders the opportunity to purchase or sell CRRs for the subsequent month. The semi-annual CRR auction is a long-term auction that consists of four separate but successive auctions – each covering a six-month period. The transmission capacity available for the auction is adjusted downward by scaling the equipment limits to lessen the risk of revenue inadequacy. Table 6.2 displays the successive semi-annual auctions and each auction's scaling factor. The scaling factor used for the monthly auctions is 90%. The remaining 10% transmission capacity is a global derate factor that is not made available to the auction participants. The global derate factor acts as insurance against uncertain events (*e.g.*, forced transmission line outage) that can lead to revenue inadequacy.

Table 6.2: Long-term auction sequence

Sequence	Period	Scaling Factor
1	0 – 6 months	60%
2	6 month – 1 year	45%
3	1 year – 1 year and 6 months	30%
4	1 year and 6 months – 2 years	15%

Bidders in each six-month auctions may submit bids for the time-of-use periods described in Section 6.3.3 except for 24-hour bids. Also, bids do not have to be for the entire six-month period – bidders may bid on a month or calendar-strip of consecutive months.

Once the long-term auction is cleared, its CRR awards are called "fixed bids" in subsequent monthly and semiannual auctions except for the last sequence (Sequence 4 in Figure 6.4) where the 15% capacity purchased in the long-term auction is the first opportunity for bidders to purchase CRRs. Fixed CRRs may be offered to be

[11] A partition of a set is a grouping of the set's elements into non-empty subsets, in such that every element is included in exactly one of the subsets.

sold in other later monthly or long-term auctions.

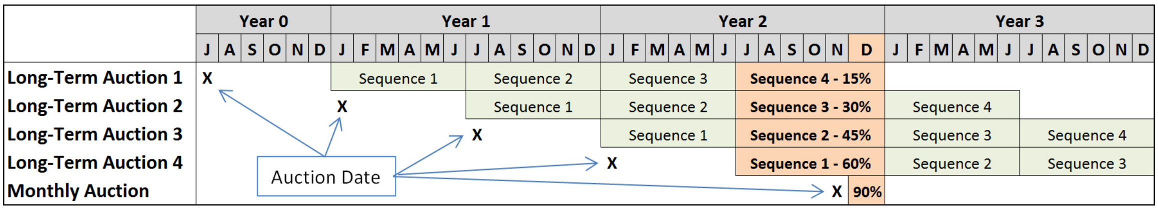


Figure 6.4: Example ERCOT CRR auction schedule to purchase CRRs for December Year 2

6.5 ERCOT's CRR auction outage imposition

According to ERCOT's market rules (Protocols, Operating Guides), the process for including planned outages of transmission into the CRR action model is a modified version of SINTO. Instead of including all outages, ERCOT models a subset of them as described in the following:

> Congestion Revenue Right (CRR) Network Model Outage determination uses network topology of the CRR Network Model identified by ERCOT. This must include Outages of Transmission Elements with a status of approved or accepted by ERCOT at the time the CRR Network Model is being built and that demonstrate significant impact to the transfer capability during the effective period. ERCOT will consider including Outages in the CRR Network Model that are scheduled to occur in the relevant time period and meet one or more of the following criteria: (i) Consecutive or continuous approved or accepted Outages greater than or equal to five days; (ii) Approved or accepted Outages which include Transmission Elements included in the definition of a Hub; (iii) Approved or accepted Outages which include Transmission Elements in a 345 kV Transmission Facility; (iv) Approved or accepted Outages that require the use of a

> Block Load Transfer (BLT); and (v) Any other approved or accepted Outage that has been determined by ERCOT to carry a substantial risk of causing significant congestion. [163]

The outages not modeled are assumed to have an insignificant effect on congestion. Thus the procedures in this operating guide section support the hypothesis provided in Section 3.4.1 that suggest a broader mindset to reduce CRR awards by only focusing on including outages that may increase congestion, without considering whether the included outages might result in CRR over-awards due to Braess's paradox.

ERCOT publishes a document called: "Whitepaper for Congestion Revenue Rights Model Build Processes [140]." This document describes in detail the methodology used by ERCOT's engineers to build the transmission model ("base case") used in the CRR auction simultaneous feasibility test.[12] The methodology groups transmission outages using a GANTT chart to visually determine days in the modeled month that have the most coincidental transmission outages in order for the CRR auction engineers to select the single "day" where the aggregate grouping of outages "create the most congestion on the system and apply those outages to the model for that month [140]."

Figure 6.5, shows an example from an ERCOT presentation [164] of a GANTT chart of scheduled transmission outages for the month. The rows in the GANTT chart contains the list of outages. Columns A through M contain descriptive information about the outages (only A - D is shown), for example, column A list the "from" station

[12]The process described in this white paper was confirmed in a meeting with ERCOT's CRR team on October 5, 2015, 2:30p central time managed by David Maggio who was in attendance.

names, column B list the "from" station abbreviation, column C list the "to" station name and column D list the "to" station abbreviation. The set of columns starting at column N contain the outage schedules by day where an "X" in the cell indicate that the outage is scheduled for that day. The two columns highlighted yellow are candidate days that may contain the single "day" where the aggregate grouping of outages ERCOT determines creates the most congestion on the system and applies those outages to the CRR auction model for that month. The selected "day" that the CRR auction engineers deem most significant to congestion represents the set of outages that is included in the CRR auction.

Two noteworthy observations can be made from the GANTT chart. The first is obvious, in that, many transmission outages are not modeled in the CRR auction using this method. This one of the trade-offs ERCOT and other RTOs make for practical implementation of the CRR auction given the auction's deadlines. The exclusion of outages that do not occur on the selected date may have an impact on revenue adequacy as discussed in Section 2.2. However, the contribution of this thesis and its case study is about the impact of Braess's paradox and SINTO on the CRR auction. As previously presented the CHIMPO model approach would remedy this issue because it includes all the transmission outages as they are scheduled to occur. The second observation from the GANTT chart is that the date selected with the most simultaneous outages may not be simultaneous for the entire period because the outages may have different durations thus SINTO still applies.

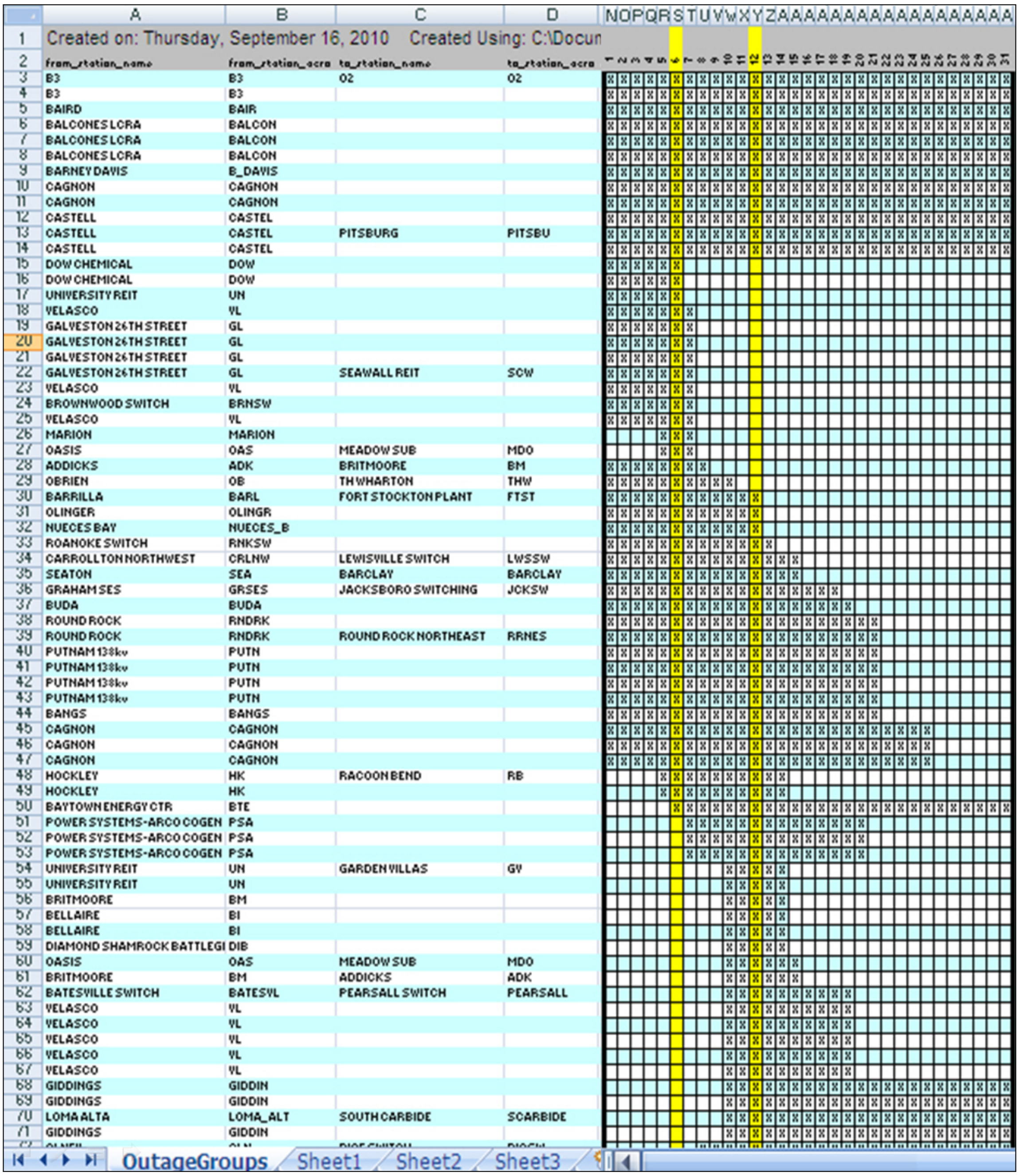


Figure 6.5: ERCOT transmission outage GANTT chart [164]

6.6 Modeling system

Nexant offers two FTR auction software solutions. The first is the iHedge FTR Market System used by RTOs to conduct FTR auctions and allocations. The second is the iHedge FTR Market Simulator for use by market participants to simulate the FTR auction in order to develop FTR bidding strategies. Both solutions are described below.

ERCOT uses Nexant's iHedge® FTR Market System. The iHedge FTR Market System is a comprehensive web-based software platform that administers and manages transmission rights and runs the FTR allocation and auction process for the ISO. ERCOT selected Nexant iHedge Solution because it is a web-based, integrated tool driven by calculation subsystem built on database subsystem and data interface subsystem that interacts with users through a market user interface (MUI) [165]. Figure 6.6, displays ERCOT's iHedge FTR Market System integrated with ERCOT's internal system for conducting ERCOT CRR auctions. The Network Model Management System (NMMS) shown on the right lower side of the diagram is used to prepare transmission models for the CRR system as well as other ERCOT systems.[13] The transmission model is then sent to the iHedge FTR Market System shown for inclusion into the CRR auction. The iHedge FTR Market System shown inside the large green shaded rectangle of Figure 6.6 includes the Data Interface Subsystem, Database Subsystem, Market Participant's User Interface, Market Operator Interface, and the CRR Calculation Subsystem. The CRR Calculation Subsystem is the same engine used in iHedge FTR Market Simulator.

The Nexant iHedge FTR Market Simulator is a standalone command line appli-

[13]ERCOT operational and planning systems include: Energy Management System (EMS), Market Management System (MMS), Outage Scheduler (OS), Congestion Revenue Rights System (CRR), Operations Training Simulator (OTS), Settlements & Billings and ERCOT Planning.

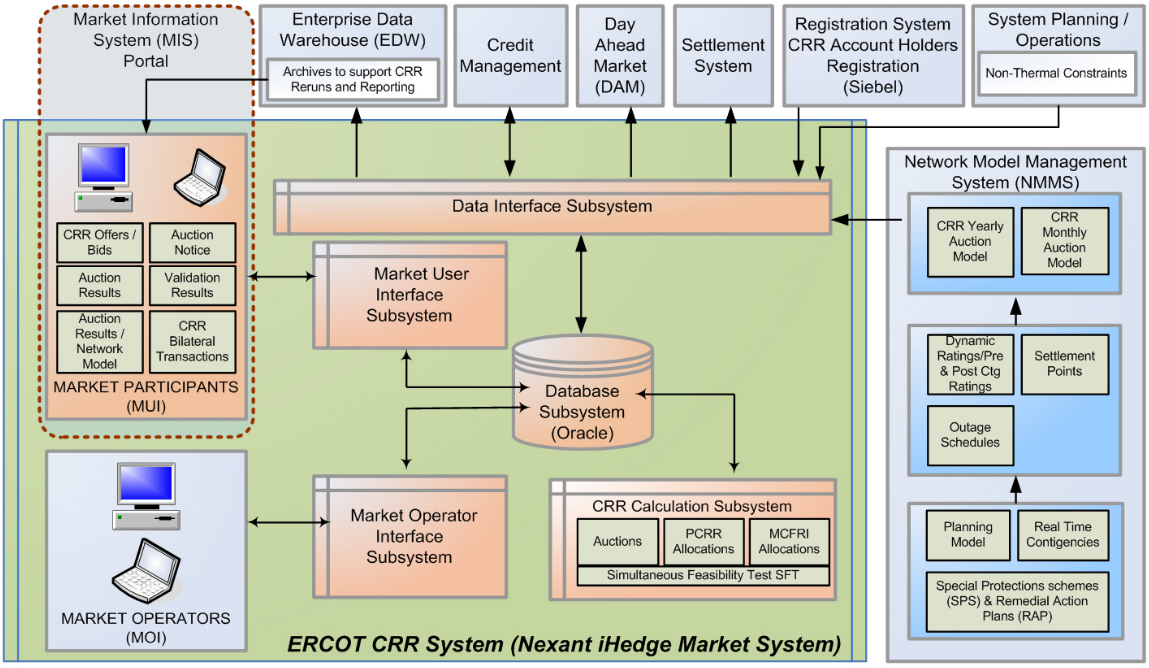


Figure 6.6: Nexant CRR system, its components & interfaces with other ERCOT systems [165]

cation that can run in a Unix or WINDOWS environment. The iHedge FTR Market Simulator is the FTR calculation system of the iHedge FTR Market System and does not include the other data management systems found in the iHedge FTR Market System, *e.g.*, the iHedge FTR Market Simulator does not include the Market Participant's User Interface where bidders submit their bids. A simple block diagram of the simulator is shown in Figure 6.7. The iHedge FTR Market Simulator works with two supporting utilities that converts ERCOT's CRR auction output files to input files for the iHedge FTR Market Simulator.

The simulation input files were prepared in a WINDOWS environment and then transferred to the Unix server for processing. Below are the steps necessary to perform

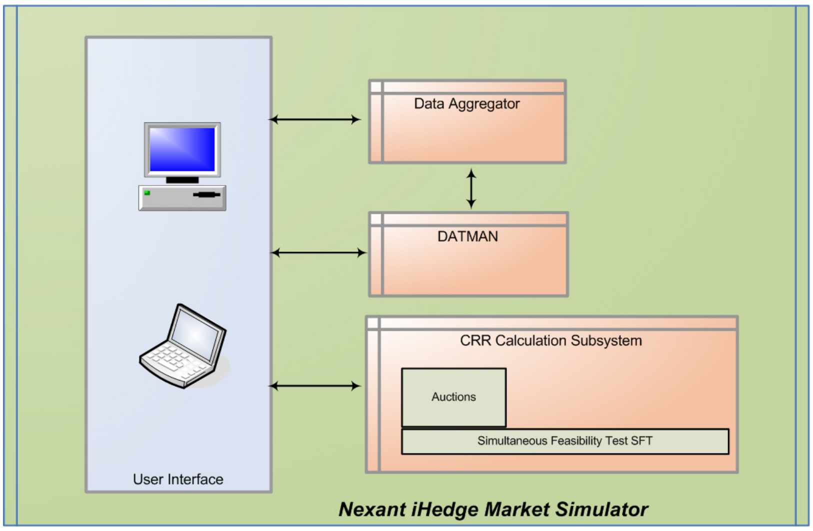


Figure 6.7: ERCOT Nexant CRR iHedge Market Simulator

a CRR auction simulation:

1. Solve the base case: This process calculates the power flows on each line using the Fixed bids from prior auctions as described in Section 6.3.4.

2. Run contingency analysis: This is performed for all periods and topologies to determine whether the Fixed bids are feasible in the upcoming CRR auction. Contingency analysis is discussed in Section 6.3.8.

3. Expand limits to ensure feasibility: Once CRRs are awarded in prior CRR auctions, the ERCOT protocols [160] specify that the line limits will be readjusted (expanded) to accommodate the flows attributed to these awards. The Fixed CRR awards may no longer be feasible in the subsequent auction as determined from the contingency analysis. From a computational perspective, the expanding limits process may be necessary to solve the auction because the new CRR

bids may not have enough controls to make the Fixed CRR awards feasible thus the auction would not be able to find a solution.

4. Run auction: Solves the multistage optimization problem.

5. Create output reports: Produces text and comma-separated values (csv) files for results, analysis, and diagnostics. The reports include the following: Branch Outage Report, Expanded Limits Report, Objective Function Value Report, Binding Constraints Report, Binding Constraints Sensitivity Report, and CRR Awards Report.

Software selection rationale

Nexant iHedge® FTR Market Simulator[14] is the software used to conduct the modeling for the case study. iHedge® was chosen for the following reasons:

- Access to Nexant's knowledgeable staff who are the leading experts of FTR auctions process and auction software.
- Nexant iHedge® is the commercial application used by most RTO/ISOs to conduct their FTR auctions.[15]
- It has the capability to be set up as a multi-period model and can be configured to model formulations proposed in Sections 5.1 and 5.2.

[14] http://www.nexant.com/software/ihedge

[15] iHedge® is directly used by NYISO, MISO, CAISO, ERCOT, and SPP; has been used by PJM and NEISO to verify their primary auction software

- It has the capability to model Point-To-Point Obligation and Options FTRs
- It is capable of modeling transmission contingencies.
- It can model aggregate bids and offers: hubs, zones, commercial pricing nodes (CPNodes).
- It can replicate exactly FTR auction results.[16]

6.7 Case study data and model preparation

The process for data and CRR auction model preparation for the CHIMPO, NO-SINTO, SINTO and NO simulations is described below.

The case study modeling process is illustrated in flow diagram Figure 6.8. All data used in the model is attained from ERCOT's Market Information System (MIS) [145]. The CRR data download uses both pre- and post- CRR auction data. The pre-auction data packet includes the following data:

- Fixed Bids file: File containing CRR awards that were awarded in previously held CRR auctions as explained in Section 6.3.4.

[16]The objective in this case study is not to compare the modeling results to historical market auction results. Nevertheless, this analysis was performed, and the results are almost identical to the CRR auction results with the main difference attributed to budget and credit constraint data not being publicly available for the bidders.

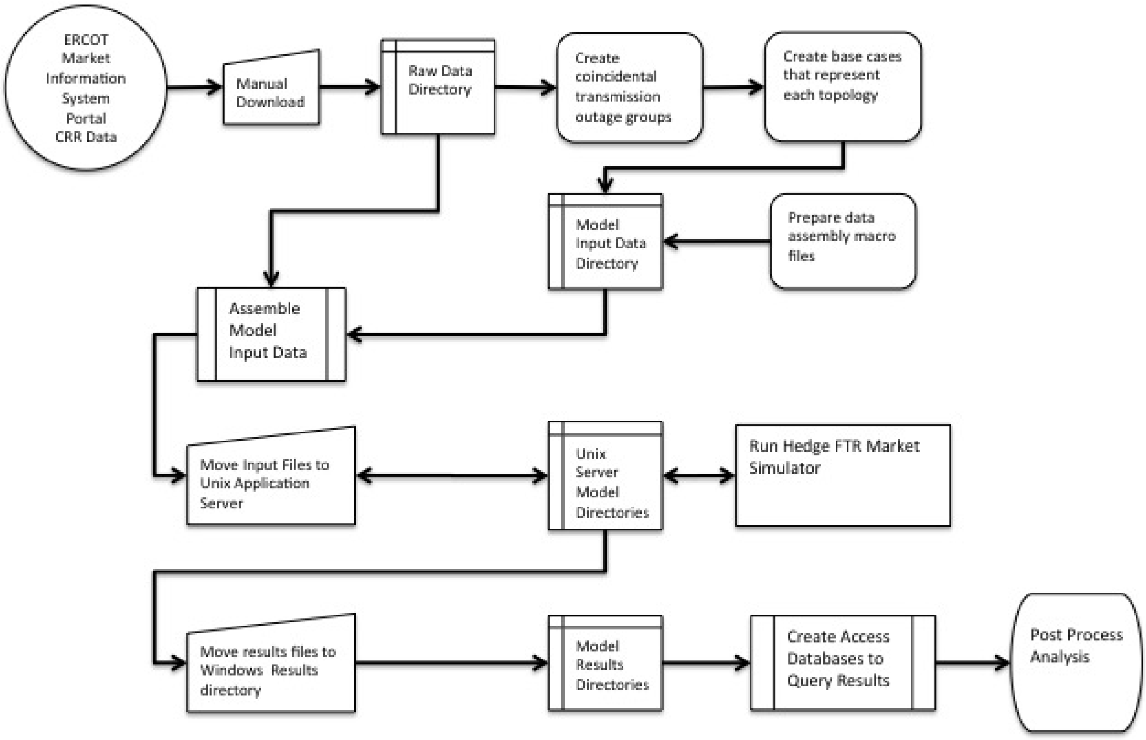


Figure 6.8: Case study CRR auction modeling process

- Base cases files: Three base cases - one for each period - are provided with the data package. However, all three base cases are the same, and all SINTO transmission outages are reflected in the base cases that the CRR team included in the model.

- Contingency file: The contingency includes the contingency elements to be evaluated by the simultaneous feasibility test. Contingency analysis are explained in Section 6.3.8.

- Monitored elements files: File contains a list of the devices/equipment with their associated base case and emergency ratings.

- Source and Sink definitions file: This file provides the Settlement Pricing Point (SPP) node-to-bus mappings and associated weighting factors for both single and aggregate nodes. SPPs are explained in Section 6.3.2.

- Dynamic ratings' file: Static table with the temperature assumptions for each weather zone used to determine the dynamic line limits.

- Non-thermal constraints file: File includes a list of generic constraints. Generic constraints are interface constraints (a group of transmission lines) that are given a limit (typically for stability, voltage or other constraint that cannot be modeled in a power flow application) to limit geographic area power transfers. Generic constraints are explained in Section 6.3.7.

- Mapping file: File provides a mapping between the operations equipment names and the CRR base case.

- GIS bus file: Google Earth .kml file containing the GIS coordinates for ERCOT's transmission system buses and lines.

- Transmission outage text file: File contains a snapshot of all the transmission outages considered for the CRR auction. Only a subset of the outages is selected to be included in the auction as explained in Section 6.5.

- Flowgate file: ERCOT CRRs are Point-to-Point FTRs and the stakeholders have not adopted the use of Financial Flowgate Rights (FGR) thus the file is empty.

The post-auction data packet includes the following files:

- Cleared CRR awards file: File contains the unmasked cleared bids and offers awarded for the monthly CRR auction including the bid description, clearing price and quantities.
- Submitted Bids and Offers file: File contains all masked bid and offer data for the auction.
- CRR auction binding constraints: File contains monthly auction binding constraints and shadow prices.
- Source and sink shadow prices: File contains the prices for the commercial pricing nodes.

6.7.1 CHIMPO CRR auction simulation process

The base case and outage data are prepared for the CHIMPO simulations by first creating a GANTT chart to manually create sets of coincidental transmission outages (topologies) that occur during that month. ERCOT adopted this outage inclusion process because removing all of the non-coincidental outages scheduled for a month may not be operationally feasible.[17] Figure 6.9 shows the GANTT chart prepared for

[17] An ancillary benefit of the CHIMPO formulation is that all transmission outages can be included in the model.

the May 2014 CHIMPO auction simulation. In the GANTT chart, each row indicates the transmission line or transformer planned for an outage and a red colored cell with a “1” in it indicates an outage scheduled for that day. Conversely, green cells with a “0” indicate that the equipment does not have an outage on that day. As explained in Section 6.5, the outages modeled in the CRR monthly auction are only a subset of the total number of outages scheduled during the month – where the ERCOT CRR engineers select the day where the group of outages is determined to have the greatest impact on congestion (the day with the most limited transmission capacity in the month). It is obvious that on the day selected the outages are simultaneous; however, because the outages may have different durations (*e.g.*, one outage has a 5 day duration, and another outage has a l5 day duration and may only be coincidental on the day selected) the outages may not all be coincidental for every period during the month. As seen in the GANTT chart shown in Figure 6.9, ERCOT selected May 2nd as the day with the most limited transmission capacity. Also, note that the transmission configurations due to the planned outages are different when comparing May 2nd to May 31st thus the May 2nd outages are not coincidental for the entire period. Another example, showing that the day with the most limiting coincidental grouping of planned outages are not coincidental for the entire period can be seen in the GANTT chart prepared by ERCOT shown in Figure 6.5.

In addition to the scheduled outages shown for example in Figure 6.9, ERCOT includes outages when creating the base case that can not be manipulated in the base

					May																														
From Bus Name	To Bus Name	Circuit ID	PLANNED START_DATE	PLANNED END_DATE	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31
L_GERONI8_1Y	L_MCQUEE8_1Y	1	3/5/2014 0:01	6/1/2014 0:00	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
BLOOSOM_T8	TNBLOSSOM_1	1	8/1/2013 9:24	5/30/2014 18:00	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0
TNNALVIN__1	MEADOW__138A	1	11/6/2013 9:55	5/30/2014 17:00	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0
NADASUB9	L_COLORA9_1Y	1	4/1/2014 11:00	7/1/2014 16:00	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
L_FLATON8_1Y	L_PLUM__8_1Y	1	12/2/2013 7:00	5/30/2014 18:00	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0
L_RAYMBA8_1Y	L_KERRLE8_1Y	1	4/23/2014 0:01	8/31/2014 23:59	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
L_WHITES8_1Y	L_BUTTER8_1Y	1	3/4/2014 12:00	5/31/2014 18:30	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
L_DEANVI8_1Y	L_LEXING8_1Y	1	5/1/2014 7:00	7/18/2014 19:00	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
L_MAGNTA9_1Y	L_HELENA9_1Y	1	3/24/2014 7:00	6/6/2014 18:00	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
L_RAYMBA9_1Y	L_LEGION9_1Y	1	3/31/2014 7:00	5/23/2014 18:00	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	0	0	0	0	0
L_HIGH128_1Y	L_CUSHMA8_1Y	1	2/26/2014 0:00	5/30/2014 23:59	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0
LOVING_8	ELMAR_8	1	3/4/2014 7:00	6/1/2014 19:00	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
ALIBATES	AJ_SWOPE	1	3/12/2014 0:00	5/7/2014 10:10	1	1	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
WINDMILL	AJ_SWOPE	1	3/12/2014 0:00	5/7/2014 10:10	1	1	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DOEDYNSUB8	ALBERTARDSB8	1	2/17/2014 8:00	5/23/2014 18:00	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	0	0	0	0	0
BARL4A	ALMC4A	2	4/30/2014 7:00	5/14/2014 18:00	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BROADVEW	FIVE_PTS	1	11/11/2013 8:00	5/30/2014 17:00	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0
FTST4A	BARL4A	1	4/30/2014 7:00	5/14/2014 18:00	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BENDER_86	CONNER__138X	86	3/14/2014 18:01	5/22/2014 18:00	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	0	0	0	0	0	0
BIG_FOOT2A	DEVINE2A	1	3/10/2014 9:00	5/30/2014 16:00	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0
BOSQUESW5	ELM_MOTT__5	1	4/28/2014 8:00	5/2/2014 18:00	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BRINE___138A	LNGSTN_138X	86	1/8/2014 18:01	5/22/2014 10:57	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	0	0	0	0	0	0
COOPERCK	ARCO_T_8	1	3/26/2014 0:00	9/2/2014 17:00	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
EDNASUB9	CORDELESUB9	1	4/14/2014 8:00	5/12/2014 17:00	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SU_STLAWREN	SU_EILAND	1	3/20/2014 9:00	5/15/2014 19:00	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ENLOE_SW	LAKE_CREEK	1	8/16/2013 14:14	8/15/2014 17:00	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
ENLOE_SW	LKCRK_P8	1	8/16/2013 14:14	8/15/2014 17:00	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
SU_STLAWREN	SU_E_STILES	1	3/20/2014 9:00	5/15/2014 19:00	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
L_FERGUS8_1Y	180017	1	10/21/2013 0:01	5/8/2014 12:00	1	1	1	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
KUYDAL745005	RTHWOD__345A	74	4/14/2014 6:00	5/2/2014 11:59	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LA_PALMA7A	RIOHONDO7A	1	1/22/2014 0:00	9/30/2014 16:00	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
LON_HILL2A	RBSTN T2	1	2/19/2014 17:01	5/7/2014 19:00	1	1	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PAWNEESW5	LNHILL 6	1	4/9/2014 7:00	5/2/2014 19:00	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
RIOHONDO7A	NEDIN7A	0	4/25/2014 19:01	5/2/2014 19:00	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
RIOHONDO7A	NEDIN7A	1	4/7/2014 7:00	5/2/2014 19:00	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SILVERCITY	CALVERTSW	1	4/15/2014 7:00	5/31/2014 20:00	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
BOOTS4A	WCSLR_100PVA	1	12/3/2013 0:00	5/15/2014 23:59	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
STEPHENVIL8	STPHNVIL_8	1	3/17/2014 7:00	5/15/2014 21:00	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CROSBY__138A	CONNER__138X	86	3/14/2014 18:01	5/22/2014 18:00	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	0	0	0	0	0	0
KUYDAL745005	TOMBAL__345B	74	5/2/2014 12:00	5/2/2014 17:00	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LNGSTN_138X	MT_BEL__138B	86	1/8/2014 18:01	5/22/2014 10:57	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	0	0	0	0	0	0
FERGST1	FERGST1_1_8	G1	10/21/2013 0:01	5/8/2014 12:00	1	1	1	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FO_FORMOSG11	FORCFB_1_8	1	11/1/2013 11:00	5/31/2014 10:00	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
LYTTON13	LYTTON34	3	11/28/2013 17:00	6/1/2014 0:00	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
MEADOW__345A	MDO_STAR	A1	11/6/2013 9:55	5/13/2014 23:59	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
WCSLR_100PVA	WCSLR_100PVB	T1	12/3/2013 0:00	5/15/2014 23:59	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Figure 6.9: May 2014 transmission outage GANTT chart

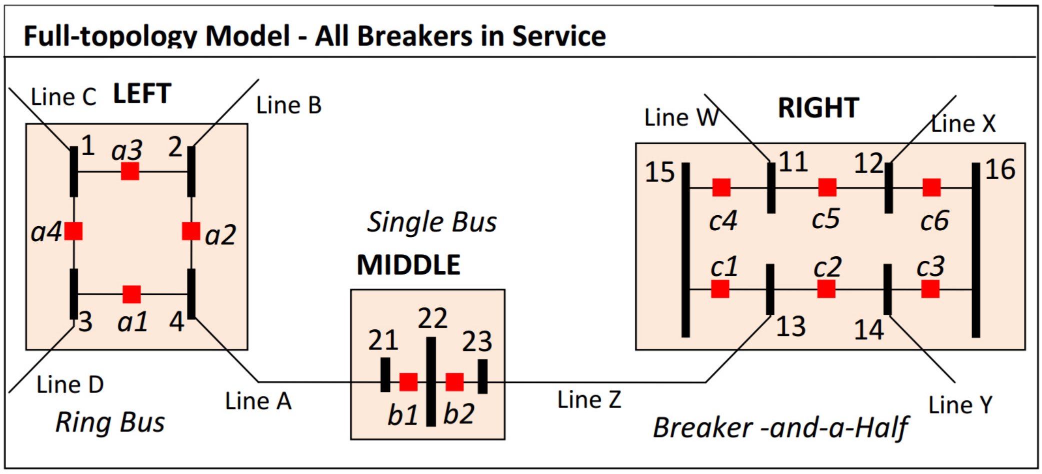
case and thus the outages cannot be controlled for the case study. These outages are listed in the transmission outage file mentioned in Section 6.7 that is provided to the market participants before the auction. The reason that some equipment outages cannot be adjusted in the base cases provided by ERCOT (and all other RTOs) is because the power industry uses two types of topology models – one for the operation and the other one for the planning of the power system.

The transmission outage file includes electrical equipment outages such as breakers and disconnect switches that cannot be modeled in a planning-type Bus-Branch model (base case) ERCOT uses in the CRR auction. The two types of topology models are the Node-Breaker network model used by system operations and the Bus-Branch network model used by transmission planners [166,167]. Node-Breaker network models represent substation[18] equipment in much greater detail than the Bus-Breaker network model and so it is more capable of modeling actual transmission system configurations. Conversely, the Bus-Branch network models contain no breakers or disconnect switches and are more limited in the transmission configuration that can be represented. For example, in Figure 6.10a the network Node-Breaker model is illustrated where the red squares are breakers, and the black rectangles are buses, and the planning Bus-Branch model corresponding to the network model is shown below in Figure 6.10b. Notice that all three substations in the Node-Breaker model are each modeled with a single bus in the Bus-Branch model. The CRR base case originates as a network operations model (Node-Breaker) where equipment like breakers and disconnects can be taken out-of-service. Once the outages are modeled, the CRR engineers create a Bus-Branch base case from the Node-Breaker network model using a program called a topology processor [168].[19] After the Bus-Branch base case is created, equipment like breakers and disconnect switches can no longer be modified. Thus, in the case study, the GANTT chart created from the transmission outage

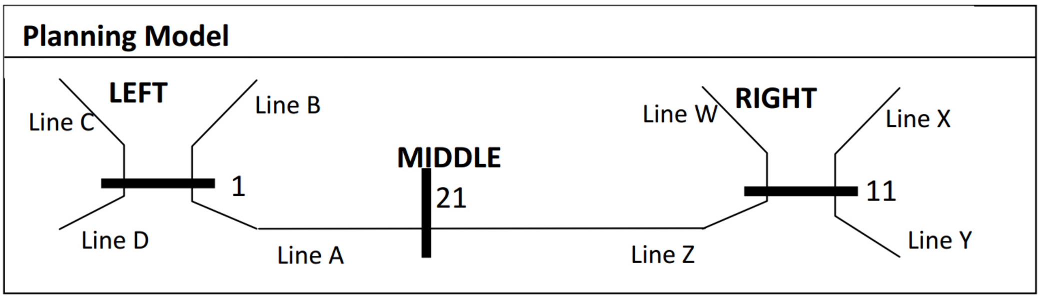
[18]A substation is a power system facility that encompasses the following physical equipment: transformer, breakers, disconnect switches, electrical buses, metering and relaying devices, and control and communication systems. A substation serves several functions including a connection point for transmission lines, an interconnection point for generators or loads (or to distribution systems), voltage conversion, facilitate maintenance, power system measurements, power system protection, and remote control equipment.

[19]The topology processor conversion depends on the operational state of the breakers and disconnects.

file to create coincidental outage groups only considers transmission and transformer outages.



(a) Node-Breaker Model



(b) Bus-Branch Model

Figure 6.10: Substation model representation (a) Node-Breaker (b) Bus-Branch [169]

After creating the GANTT chart, the next step is to build base cases that incorporate the coincidental outage topologies. Since ERCOT already included the outages into the auction base cases provided in the pre-auction data package, the task was to determine which lines to place back-in-service instead of which to take out-of-service. In addition to the transmission outages, the base case also includes open transmission lines that are either where the operating state is normally open or are future lines that are not in-service yet. This means that closing all the lines in the base case and then imposing the transmission outages was not an option in preparing the base cases.

After the base cases are prepared, the next step is to assemble the data into a set of iHedge FTR Market Simulator input files. Two programs are used: the Data Aggregator and DATMAN. The Data Aggregator is a utility that reads the ERCOT CRR data files as provided by ERCOT and converts the data into Partial PCA[20] data files and DATMAN macro files. The initial DATMAN macro files and partial PCA files are configured to create files for a SINTO CRR simulation and are subsequently modified to a CHIMPO configuration. Following that the second utility called DATMAN reads the modified DATMAN macro files assembles the PCA input files for iHedge FTR Market Simulator.

Table 6.3 displays the number of topologies modeled for the CHIMPO CRR auction simulations which are a product of the number of outage configurations considered and the number of TOU periods.

The last column in Table 6.3 displays the total number of combined TOU period and topology PCA files created per simulated month. One additional PCA file is created called the Multiperiod PCA file. Lastly, an iHedge macro file is created with commands that perform the necessary steps to run the simulation and generate and name the output results files. The output reports produced for analysis include

[20]PCA stands for “Power Computer Applications” after the name of the company before Nexant Inc. acquired it in 2000

Table 6.3: Modeled CHIMPO topologies

	CHIMPO		
	No. Topologies	No. TOU Periods	Total Combined
Jan-14	10	3	30
Feb-14	7	3	21
Mar-14	9	3	27
Apr-14	13	3	39
May-14	12	3	36
Jun-14	11	3	33
Jul-14	3	3	9
Aug-14	7	3	21
Sep-14	5	3	15
Oct-14	13	3	39
Nov-14	22	3	66
Dec-14	18	3	54

the following: Branch Outage Report, Expanded Limits Report, Objective Function Value Report, Binding Constraints Report, Binding Constraints Sensitivity Report, and CRR Awards Report. The iHedge macro file and PCA files are then moved to the iHedge FTR Market Simulator Unix application server directory. This directory also houses the auction simulation results files. A Unix script file initiates the twelve CHIMPO simulation and iterates through each monthly auction run.

After the CHIMPO CRR auction simulations are completed, then the output and diagnostic reports are moved back to the WINDOWS results directory and are analyzed. The output reports are either text or csv files, and Access databases are created to query the results.

6.7.2 NO SINTO, NO and SINTO CRR auction simulation process

The process for the NO-SINTO CRR auction simulations is the same as CHIMPO except only two topologies are prepared. The first is the SINTO base case provided as-is by ERCOT and another "Normal Operations" base case prepared by placing the scheduled transmission outaged lines back in-service. As in the preparation of the CHIMPO topologies, transmission lines and transformers that are either normally opened or not in service are not altered. The NO CRR simulations are prepared using the base case created for the NO-SINTO CRR simulation; however, only one topology is used in the simultaneous feasibility test. Lastly, the SINTO CRR auction simulation uses ERCOT's CRR auction data without modification.

6.8 Study general approach and methodology

6.8.1 Specific questions to be addressed by the methodology

As explained in Section 5.1, the CHIMPO formulation is the ideal SFT approximation because constraints for all the unique transmission system configurations due to the planned transmission outage schedule for the month are precisely represented. Although the CHIMPO formulation is the ideal solution, its main drawback is the additional computational time required to consider multiple configurations within a month may not meet the market deadlines to run the auction, analyze results, rerun if necessary and finally notify the auction participants of their results. For the case study, CHIMPO simulations are used to accomplish two purposes. The first is to detect the presence of Braess's paradox and SINTO by comparing the SINTO results to the CHIMPO. The CHIMPO CRR simulation is the benchmark for the case study. The second purpose is to assess if the NO-SINTO approach is a better approximation to the full CHIMPO model than the SINTO approach. Lastly, the case study approach considers computational performance by comparing computational times for each of the formulations.

This case study procedure is developed to answer the following questions. In turn, these questions are separately addressed in the sections from Section 7.2 to Section 7.6.

1. Did Braess's paradox impact the CRR auction results?
2. How were the auction results affected?
3. Did the proposed formulations reduce the effects of Braess's paradox and the simultaneous imposition of non-coincidental transmission outages?

4. Which formulation (SINTO or NO-SINTO) had better results when comparing their allocations to CHIMPO allocations, and why were those results better?

5. Can the proposed formulations be practically implemented? If not, why?

6.8.2 Test methodology and procedure

Below is a description of the procedure and methods for the case study:

1. Prepare CRR auction simulation data for the NO, SINTO, NO-SINTO, and CHIMPO CRR auction formulations as described in Section 6.7.

2. Simulate ERCOT's CRR auction results by running the SINTO formulation

3. Run CRR auctions with the two proposed modified formulations: CHIMPO and NO-SINTO

4. Run the CRR auctions without planned transmission outages: Normal Operation (NO)

5. Collect model run performance statistics, *e.g.*, computation time, model run failures, size of results data

6. Aggregate iHedge model output data: large model output data in text and comma separated values (.csv) files imported into an Access Database and queries developed to aggregate the data to be analyzed

7. Compare simulation results

    - Transmission limit expansion report analysis. This comparison examines whether previously awarded CRR, Fixed CRRs, remain feasible in the monthly auction. Comparison metrics include: correlation, RMSE (Roots Mean Square Error), and comparing totals.
    - Use metrics to investigate and explain differences among the various model runs using the CHIMPO simulations as the benchmark.

8. Summarize and document findings

In the next chapter, the results of applying the above procedures to the case study are presented.

Chapter 7

ERCOT Case Study Results and Analysis

7.1 Introduction

The primary objective of this chapter is to answer the five research questions posed in Section 6.8.1 using the case study CRR auction simulation results. Each of these five questions is addressed in a separate section below. In Section 7.2, the first inquiry is to determine if the case study found evidence of the Braess's paradox affects in the SINTO CRR auction results. In Section 7.3, the second question is to analyze how the auction results were affected by Braess's paradox. The third question presented in Section 7.4 assesses whether the proposed NO-SINTO and CHIMPO formulations reduce the impact of Braess's paradox and SINTO. Then in Section 7.5, the fourth question appraises which formulation, SINTO or NO-SINTO, provides a CRR result closest to the ideal CHIMPO result. Lastly, in Section 7.6, the fifth question examines whether the proposed formulations can be practically implemented. As previously discussed in Section 6.8.1, the CHIMPO simulation results are used as the benchmark for the case study because it uses the various transmission configurations derived from the planned transmission outage schedules which most accurately represent the planned day-ahead market transmission configurations.

In all, forty-eight CRR auction simulations (twelve - 2014 monthly CRR auctions for each of four formulations: CHIMPO, NO-SINTO, SINTO, and NO) were performed and output data aggregated to produce data sets of results used to answer the five case study research questions. A standard non-parametric hypothesis test is used to determine a quantitative index of the strength of the differences between the models.[1]

In addition to analyses of the above five questions, a modification to the NO-SINTO model is proposed and tested that improves its performance. In particular, in Section 7.7, a subsequent modification is made to the NO-SINTO formulation based on a hypothesis that adding outages lasting the full month to the NO constraints of the NO-SINTO model would improve its approximation to the CHIMPO model results. The modified model, called the Adjusted NO-SINTO model, is then run for the twelve month test period and the Objective Function Values (OFV) compared to

[1]In this case, the results of the hypothesis test are not to be interpreted as actual probabilistic statements of statistical significance.

the OFV results of the other approaches to determine if the approximation improved.

In Section 7.8, the case study result findings are summarized.

7.2 Question 1: Did Braess's paradox impact the case study results?

7.2.1 Detecting the paradox with the objective function values

In its most basic form, a circuit exhibiting Braess's paradox is simple to assess; for example, as in the specifically designed Wheatstone bridge circuit used in this thesis (Chapter 4) and other academic work [153, 170] that considers only one flow from a start node (source) to a destination or end node (sink). However in a large transmission system with many circuit configurations and many superimposed power flows, affirming whether the paradox occurs is a challenging task.

Blumsack in [37] proposed a network decomposition through a graph theory approach to identify embedded Wheatstone sub-networks in a transmission system. However, he also proved that the explicit identification of the circuit in itself does not mean a Braess's paradox situation exists. In [153], Blumsack also showed that, unlike in transportation systems, the presence of a Wheatstone bridge configuration in power systems is neither a necessary nor a sufficient condition for Braess's paradox to occur. Even if it met the necessary and sufficient condition, it would be a very complex task to identify the transmission outages that cause Braess's paradox in an actual system. This is because contingency analyses change circuit configurations and due to CRR option constraints that only model flows in one direction (where flow induced by the option is equal to the max(0, positive flow)), Sections 6.3.8 and 6.3.5 respectively.

The approach taken to answer whether Braess's paradox affected the CRR auction results in this case study is diagnosed by comparing the objective function values for the alternative formulations and other results data. In Figure 7.1, the objective value is represented by the area under the bid curve that clears the auction (area left of the vertical transmission capacity supply line). If an outage causes Braess's paradox, then the objective function value could increase since the outage might enable more of the higher value bids to clear the auction. Observing an increase would clearly indicate that the outage has caused Braess's paradox. On the other hand, if an outage decreases the objective function, then there is no evidence of Braess's paradox. (It is possible that an outage increases network capacity for some combinations of injections and withdrawals, but decreases it for others; so an observation that the objective has worsened does not mean that an increase would not be observed under some other set of bids. Thus, observing a decrease does not necessarily rule out the occurrence of Braess's paradox.)

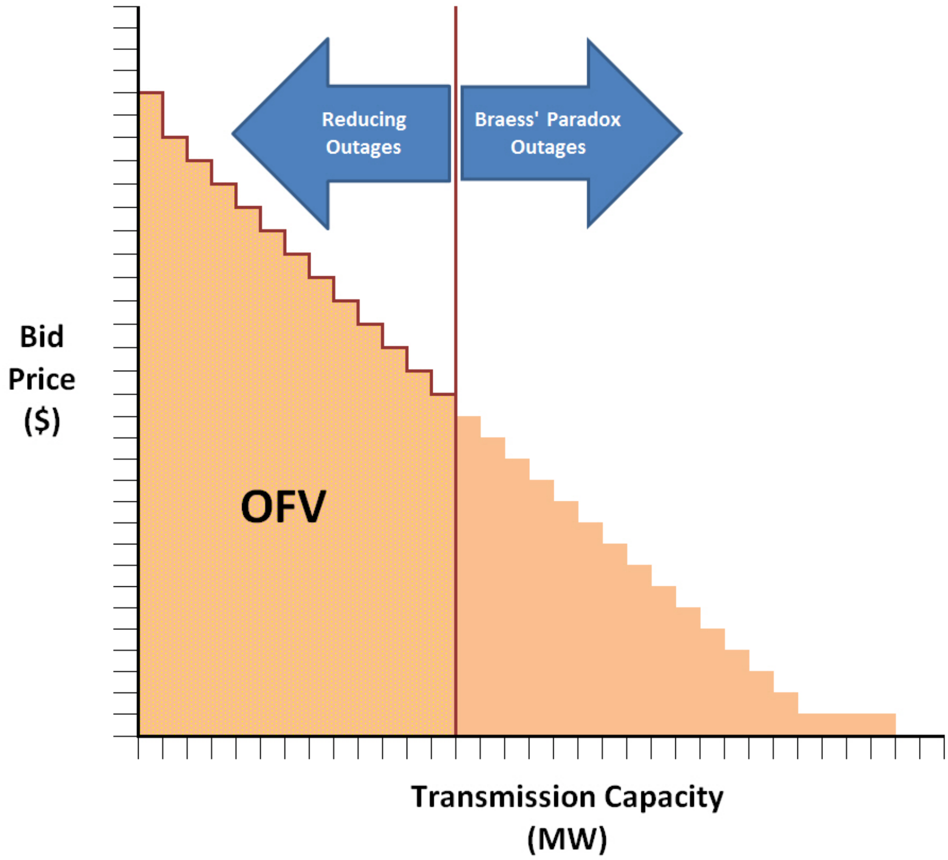


Figure 7.1: Using OFV to detect Braess's paradox

Now, consider the NO-SINTO approximation (Section 5.2) where the mere addition of a set of counter-intuitive constraints is added to the SINTO SFT to limit the flows – not a set with more outages but instead a set with no outages whatsoever. If transmission outages always reduce capacity, then the additional set of constraints with no outages should not bind in the CRR auction optimization, and the NO-SINTO objective value would be no worse than the SINTO objective value. However, if the outages cause a Braess's paradox effect, then the constraints based on the no planned outages (Normally Operated) case could limit the flow if a transmission outage increases transmission capacity, resulting in a NO-SINTO objective value that is worse than the SINTO objective value.

This same concept is also apparent in the CHIMPO formulation including outages lasting less than a month because its set of transmission constraints would include every transmission configuration that can occur in the month, and the most limiting condition would limit the flows.[2] The approach is similar to the transmission switching dispatch optimization [14] where the optimization does not explicitly determine transmission outages in circuits that exhibit Braess's paradox but instead implicitly considers Braess's paradox when the optimization reduces congestion by removing lines from their normally operated position.

Thus, the first set of analyses undertaken to determine if Braess's paradox impacted the CRR auction results is to compare the SINTO formulation objective function values to the NO-SINTO and CHIMPO values. If the SINTO would naively be expected to be the most conservative CRR auction approximation (as it imposes all outages at once in one network configuration), SINTO's flows induced by the awarded bids (and offers) (for a given set of outages and set of bids and offers) would also be expected to be feasible in both the NO-SINTO transmission configuration constraints and in the various CHIMPO transmission configuration constraints sets. Thus the

[2] CHIMPO is, in theory, less restrictive than SINTO if none of a month's sub-periods would experience all of SINTO's outages at the same time. However, if SINTO has a better objective value than CHIMPO, this would also be evidence of Braess's paradox, in that simultaneous imposition of all outages has increased capacity.

(naive) expectation for the conservative SINTO CRR auction objective function value would be that it is less or at least no more than the NO-SINTO and CHIMPO OFVs (*i.e.*, SINTO should not yield a better OFV). On the other hand, if Braess's paradox occurs, then SINTO might actually result in a better objective function value than NO-SINTO and CHIMPO. Indeed, the result below shows this.

7.2.2 Objective function values

Whether that occurred is considered in the ensuing analysis. Table 7.1 list the 48 objective function values from the CRR auction simulations applying the four CRR auction formulations to each of 12 months. The cells in the table use a green, yellow, and red color gradient across the rows. The gradient is established, so that greener shades represent smaller values, yellow represents medium values and red shades the higher values. Based on this color scheme, a general first observation is that the Normally Operated (NO) CRR auction that does not include planned transmission outages is mostly red indicating that the objective function values are higher than the other three auction formulations. If one disregards the possibility of Braess's paradox, this would be expected since more of the higher valued CRRs would likely clear the auction because it is less constrained than the other formulations that include planned transmission outages.

If Braess's paradox is not significant, then it would be expected that the objective functions would worsen (proceed from red to green) as the models add more constraints. That is, it should proceed from the NO CRR auction model (no outages) to CHIMPO CRR auction model (which does not impose all transmission outage constraints at once, but rather calculates flows separately for each), and finally to SINTO model (which imposes all outages simultaneously) and NO-SINTO model (which adds a no outages network to the SINTO case and so should not be more restrictive).

The second observation (and more surprising) is that the SINTO CRR auction objective function values are mostly colored yellow and in the medium range compared to the other CRR auction approximations. This indicates that the SINTO objective function value is higher and thus it is less constraining than the NO-SINTO and CHIMPO formulations.[3] As previously discussed, the only set of constraints added to the NO-SINTO was from a normally operated system configuration that does not include outages. This indicates that any additional transmission capacity resulting from an outage creating Braess's paradox is now limited by the normally operated transmission system constraints. This proves that Braess's paradox impacted the SINTO CRR auction allocation. Finally, like the NO-SINTO model, the CHIMPO objective function values tend to be shaded green. This shows there is some consistency between the NO-SINTO model and the CHIMPO model meaning that the CHIMPO model too acts to limit Braess's paradox.

The final row in Table 7.1 displays the twelve-month simple average of the OFVs.

[3]This result signifies that the SINTO bids would not be simultaneously feasible on the sets of network constraints from the different outage configurations in the NO-SINTO and CHIMPO formulations. This thus provides evidence that Braess's paradox impacts the SINTO CRR auction results.

A comparison of these averages and respective cell shading shows for the twelve-month period, the average of the CHIMPO and NO-SINTO OFVs were very close with a difference (NO-SINTO OFV - CHIMPO OFV) equal to $1,647. This difference which is lower than the difference between the CHIMPO and SINTO averages that has a difference (SINTO OFV - CHIMPO OFV) equal to $287,911.

Table 7.1: Objective function value comparison

	OFV			
	CHIMPO	NO_SINTO	SINTO	NO
Jan-14	18,813,774	18,838,810	18,868,647	19,629,762
Feb-14	17,314,282	17,308,897	17,356,073	18,069,044
Mar-14	23,858,408	23,729,965	23,890,777	24,345,686
Apr-14	26,615,233	26,618,446	26,636,015	32,259,907
May-14	39,067,548	39,298,710	39,466,758	43,006,401
Jun-14	40,904,656	40,965,938	42,791,244	42,213,034
Jul-14	46,634,780	46,504,649	47,022,576	47,343,031
Aug-14	38,009,087	37,867,188	38,010,900	38,018,944
Sep-14	31,552,409	31,538,607	31,559,941	32,388,375
Oct-14	29,180,333	29,197,910	29,385,808	30,771,810
Nov-14	28,768,425	28,834,513	28,969,378	30,650,288
Dec-14	25,691,370	25,726,435	25,907,119	27,131,620
Average	30,534,192	30,535,839	30,822,103	32,152,325

7.2.3 Hypothesis testing using the Sign Test

To verify that the sets of observations in Table 7.1 are statistically distinct, a nonparametric binomial hypothesis Sign Test [171] was performed for the paired differences of the monthly objective function values. Of course, use of this test assumes that the months are independent samples, which is not the case. Thus, the use in this chapter of a statistical test should be viewed as merely a quantitative indication of the extent of the differences between the solutions, and not as literally a demonstration that the results could not have happened by chance.

Hypothesis tests were performed for the following OFV combinations: NO versus SINTO, SINTO versus NO-SINTO, and SINTO versus CHIMPO. The Sign Test was chosen instead of a t-test to avoid the assumption that the distribution of the objective function values is a normal distribution. For each Sign Test a significance level of 0.05 is used. Table 7.2, list the p-values for both one-tailed and two-tailed test with the number of trials equal to twelve (n=12) because subsequent comparisons are made among the models (SINTO, NO-SINTO, CHIMPO and NO) for the twelve 2014 monthly auction simulations. The simulation results for the different auction models are paired since the monthly data results for one model is related to the corresponding monthly data of the other models.

The formulas used to calculate the binomial probability values for the 1-tailed test listed in Table 7.2 are given below. In the formulas used to calculate these probabilities, n is the total number of trials which, in this case, and for all subsequent hypothesis Sign Test, is equal to 12 (the total number of monthly simulations for a year). k is the total number of positive (+) sign differences for the trails. p is the probability of having a positive (+) sign difference in a single trial – *e.g.*, in this case, the sign is the difference between the two formulation result values being statistically tested. In the Sign Test, when the difference between the two values being tested is equal to zero, the value is disregarded and accordingly, the sample size reduced. Since only positive and negative signs are considered and equally likely, the probability for a trial is equal to 0.5. As a result, the probability of getting a negative ($-$) sign difference also has a probability of 0.5 $(1 - p)$ and is designated by the letter q. The value of the 2-tailed test shown in Table 7.2, is the probability of either tail. For example, the 2-tailed value for $P(X \geq 11)$ is actually the probability of either $P(X \geq 11 \text{ or } X \leq 1)$, and so is twice the probability of $P(X \geq 11)$.

$$P(X = k|n) = \binom{n}{k} \cdot p^k q^{n-k}$$

$$P(X \geq k|n) = \sum_{j=k}^{n} \binom{n}{j} \cdot p^j q^{n-j}$$

$$P(X \leq k|n) = \sum_{j=0}^{k} \binom{n}{j} \cdot p^j q^{n-j}$$

7.2.3.1 Are SINTO OFVs greater than the NO-SINTO OFVs?

In the absence of Braess's paradox, SINTO and NO-SINTO's objective function values should not differ. But if Braess's paradox is present, SINTO could perform better, indicating that networks with outages are sometimes less restrictive than a network with no outages. The hypothesis test follows. Let d be defined as the difference between the SINTO OFV and NO-SINTO OFV.

Table 7.2: p-values from n=12 Binomial Distribution

p-value from Binomial Distribution				
Statement	**Count (+)**	**Count (-)**	**1-tailed**	**2-tailed**
P(X = 12)	12	0	0.0002441	0.0004883
P(X >= 11)	11	1	0.0031738	0.0063477
P(X >= 10)	10	2	0.0192871	0.0385742
P(X >= 9)	9	3	0.072998	0.1459961
P(X >= 8)	8	4	0.1938477	0.3876953
P(X >= 7)	7	5	0.387207	0.7744141
P(X >= 6)	6	6	0.612793	1.0000000
P(X <= 5)	5	7	0.387207	0.7744141
P(X <= 4)	4	8	0.1938477	0.3876953
P(X <= 3)	3	9	0.072998	0.1459961
P(X <= 2)	2	10	0.0192871	0.0385742
P(X <= 1)	1	11	0.0031738	0.0063477
P(X = 0)	0	12	0.0002441	0.0004883

$$d = \text{SINTO OFV} - \text{NOSINTO OFV}$$

The null hypothesis is that the difference d is equal to zero, or stated differently, that the SINTO OFV is equal to the NO-SINTO OFV.

$$H_0 : d = 0$$

The alternative hypothesis (presence of Braess's paradox) is that the difference d is greater than zero or that the SINTO OFV is greater than the NO-SINTO OFV.

$$H_a : d > 0$$

The calculated d value is shown in the column labeled "Diff. (SINTO - NOSINTO)" of Table 7.3 and the sign of the difference is displayed in the column labeled "Sign."

Table 7.3: Hypothesis Sign Test: SINTO and NO-SINTO OFV

Yr-Mo	SINTO	NOSINTO	Diff. (SINTO - NOSINTO)	Sign
14-Jan	18,868,647	18,838,810	29,837	+
14-Feb	17,356,073	17,308,897	47,176	+
14-Mar	23,890,777	23,729,965	160,812	+
14-Apr	26,636,015	26,618,446	17,569	+
14-May	39,466,758	39,298,710	168,048	+
14-Jun	42,791,244	40,965,938	1,825,306	+
14-Jul	47,022,576	46,504,649	517,927	+
14-Aug	38,010,900	37,867,188	143,712	+
14-Sep	31,559,941	31,538,607	21,334	+
14-Oct	29,385,808	29,197,910	187,898	+
14-Nov	28,969,378	28,834,513	134,865	+
14-Dec	25,907,119	25,726,435	180,684	+
Average	30,822,103	30,535,839	Count (+)	12
			Count (-)	0

The number of positive signs is equal to 12 and number of negative signs is equal to 0. The corresponding p-value from Table 7.2 for a 2-tail test with 12 positive signs is equal to 0.00049. The result is significant since the p-value is less than the alpha value of 0.05 thus the null hypothesis is rejected, and the alternative hypothesis is accepted. This signifies that the SINTO OFVs are greater than the NO-SINTO OFVs, meaning that Braess's paradox outages were constrained by the additional NO topology constraints added to the NO-SINTO model that does not include planned outages.

In the next section, a similar hypothesis test is performed between the SINTO OFVs and the ideal CHIMPO OFVs as another indication of whether or not Braess's paradox outages impacted the SINTO simulation results.

7.2.3.2 Are SINTO OFVs greater than the CHIMPO OFVs?

Like in the preceding section but this time with the CHIMPO model, the conventional intuition is that the SINTO model is more conservative than CHIMPO model thus SINTO's OFVs should be lower or at least equal to the CHIMPO's OFVs since all the outages are modeled simultaneously in the SINTO approximation. If the CHIMPO OFVs are greater than SINTO's OFVs, the CHIMPO model would be more constrained by topologies where the outages are not scheduled to be out-of-service (for planned outages with durations less than a month). The hypothesis test follows. Let d be defined as the difference between the SINTO OFV and CHIMPO OFV.

$$d = \text{SINTO OFV} - \text{CHIMPO OFV}$$

The null hypothesis is that the difference d is equal to zero or stated differently that the SINTO OFV is equal to the CHIMPO OFV.

$$H_0 : d = 0$$

The alternative hypothesis is that the difference d is greater than zero or that the SINTO OFV is greater than the CHIMPO.

$$H_a : d > 0$$

The calculated d value is shown in the column labeled "Diff. (SINTO - CHIMPO)" of Table 7.4 and the sign of the difference is displayed in the column labeled "Sign."

The number of positive signs is equal to 12 and number of negative signs is equal to 0. The corresponding p-value from Table 7.2 for a 2-tail test with 12 positive signs

Table 7.4: Hypothesis Sign Test: SINTO and CHIMPO OFV

Yr-Mo	SINTO	CHIMPO	Diff. (SINTO - CHIMPO)	Sign
14-Jan	18,868,647	18,813,774	54,873	+
14-Feb	17,356,073	17,314,282	41,791	+
14-Mar	23,890,777	23,858,408	32,369	+
14-Apr	26,636,015	26,615,233	20,782	+
14-May	39,466,758	39,067,548	399,209	+
14-Jun	42,791,244	40,950,764	1,840,480	+
14-Jul	47,022,576	46,634,780	387,796	+
14-Aug	38,010,900	38,009,087	1,813	+
14-Sep	31,559,941	31,552,409	7,531	+
14-Oct	29,385,808	29,180,333	205,475	+
14-Nov	28,969,378	28,768,425	200,953	+
14-Dec	25,907,119	25,691,370	215,750	+
Average	30,822,103	30,538,034	Count (+)	12
			Count (-)	0

is equal to 0.00049. The result is significant since the p-value is less than the alpha value of 0.05 thus the null hypothesis is rejected, and the alternative hypothesis is accepted. This signifies that the SINTO OFVs are statistically significantly greater than the CHIMPO OFVs meaning that Braess's paradox outages were constrained by the additional constraints when outages with a duration less than a month are placed back in-service in the CHIMPO topology constraints.

In the next section, another similar hypothesis test is performed, however, in this case, it is between the SINTO OFVs and the NO OFVs. The normally operated (NO) topology does not include planned transmission outages so the naive intuition is that the SINTO OFVs should be less than the NO OFVs. The following hypothesis test determines if the difference between the larger NO OFVs and the lesser SINTO OFVs is statistically significant.

7.2.3.3 Are NO OFVs greater than SINTO OFVs?

The purpose of this hypothesis test is to verify whether the NO model that does not include planned transmission outages is less constrained than the SINTO model. Therefore the added NO topology constraints in the NO-SINTO model should not cause the NO-SINTO model to be more limiting than the SINTO model. The conventional intuition is that the outages would reduce transmission capacity; thus the NO OFVs should be larger than the SINTO OFVs. The hypothesis test follows. Let d be defined as the difference between the NO OFV and SINTO OFV.

$$d = \text{NO OFV} - \text{SINTO OFV}$$

The null hypothesis is that the difference d is equal to zero or stated differently that the NO OFV is equal to the SINTO OFV.

$$H_0 : d = 0$$

The alternative hypothesis is that the difference d is greater than zero or that the NO OFV is greater than the SINTO OFV.

$$H_a : d > 0$$

The calculated d value is shown in the column labeled "Diff. (NO - SINTO)" of Table 7.5 and the sign of the difference is displayed in the column labeled "Sign."

The null hypothesis is that the difference d is equal to zero or stated differently that the NO OFV is equal to the SINTO OFV. The number of positive signs is

Table 7.5: Hypothesis Sign Test: NO and SINTO OFV

Yr-Mo	NO	SINTO	Diff. (NO - SINTO)	Sign
14-Jan	19,629,762	18,868,647	761,116	+
14-Feb	18,069,044	17,356,073	712,972	+
14-Mar	24,345,686	23,890,777	454,909	+
14-Apr	32,259,907	26,636,015	5,623,892	+
14-May	43,006,401	39,466,758	3,539,644	+
14-Jun	42,213,034	42,791,244	(578,211)	-
14-Jul	47,343,031	47,022,576	320,455	+
14-Aug	38,018,944	38,010,900	8,044	+
14-Sep	32,388,375	31,559,941	828,435	+
14-Oct	30,771,810	29,385,808	1,386,003	+
14-Nov	30,650,288	28,969,378	1,680,910	+
14-Dec	27,131,620	25,907,119	1,224,501	+
Average	32,152,325	30,822,103	Count (+)	11
			Count (-)	1

equal to 11 and number of negative signs is equal to 1. The corresponding p-value from Table 7.2 for a 2-tail test with 11 positive signs is equal to 0.00634. The result is significant since the p-value is less than the alpha value of 0.05 thus the null hypothesis is rejected, and the alternative hypothesis is accepted. This signifies that the NO OFVs are statistically significantly greater than the SINTO OFVs. This confirms the conventional intuition that the aggregate impact of the outages included in the SINTO model has the aggregate effect of reducing transmission capacity. This, however, is not always the case, for example, it can be observed from Table 7.5 that in June the aggregate effect of including the outages in the SINTO model made the OFV greater than the NO model OFV.

7.2.3.4 Discussion

The Sign Tests' results validate the observations based on the color gradient in Table 7.1 in which the NO CRR OFVs are greater than the SINTO OFVs, and the SINTO CRR auction OFVs are in turn greater than both the NO-SINTO and CHIMPO OFVs.

As expected, the NO CRR auction OFVs usually have the highest values because it is less constrained than the other CRR auction formulations which include the planned transmission outages. Only if Braess's paradox had a very strong effect would the reverse be the case. One interesting observation is that this may not always be the case. For example, the OFV for the SINTO CRR auction was greater in June than the NO CRR auction OFV, implying that the aggregate set of outages in the SINTO exhibited the Braess's paradox effect to the extent that it was less constrained than the normally operated state of the transmission system with no outages.

The hypothesis test also confirms a second more important observation from Table 7.1 in that the OFVs for both the NO-SINTO and the CHIMPO are less than the SINTO, indicating that they are more constrained than the conservative SINTO CRR auction approximation.

The impact of Braess's paradox is evident since each formulation modeled the same number of outages but the SINTO OFV was, in fact, less constrained (higher OFV) than both the NO-SINTO and CHIMPO auction simulations. In the case of the NO-SINTO formulation, the only set of constraints added that makes it different than the SINTO constraints are from a second topology that does not include outages. One can deduce that the additional constraints that lowered the NO-SINTO OFV were caused by the second topology with no planned outages, meaning that the SINTO topology was less constrained because some of the outages modeled increased transmission capacity compared to the no planned outage case (Normally Operated) instead of reducing it. This analysis answers the first case study research question (Section 6.8.1) and provides evidence that Braess's paradox impacted the SINTO CRR auction allocation.

7.2.4 Additional evidence of Braess's paradox in the fixed dids SFT

Next an analysis of the overloads from previously allocated CRRs (called Fixed bids) is provided to show more evidence that the SINTO CRR auction formulation simultaneous feasibility test (SFT) is less constrained due to the impact of Braess's paradox arising from the modeled planned outages. As part of the ERCOT's CRR auction process, a simultaneous feasibility test is conducted on the Fixed bids before the CRR auction to determine if they cause overloads due to the transmission outages scheduled for the monthly auction [160, 172]. As explained in Section 6.4, the prior CRR auctions allocate up to 60% of the transmission system capacity by reducing the transmission lines ratings. ERCOT allocates up to 90% of the transmission system capacity for the monthly auctions. However, the transmission outages modeled in the monthly CRR auction may make some of the previously awarded Fixed bids infeasible when ERCOT performs a pre-auction SFT due to the redistribution of flows caused by the outages. The SFT is an application that can be run independently from the auction optimization to identify overloads from Fixed bids. After the SFT is completed, the limits of any overloaded constraints are increased to the flows on the lines. This is performed in order to honor the previously awarded Fixed CRR bids and avoid starting with a known infeasibility issue that may not be resolved by the auction optimization. This is applied to each of the models to determine whether the Fixed CRRs alone are feasible. If Braess's paradox is not present, then the expectation is that the SINTO model would show at least as many violations as the CHIMPO model, and the same number as the NO-SINTO model because the outages would similarly reduce transmission capacity in all three models. But if Braess's paradox is operating, SINTO might have fewer violations.

A summary of the overloads cause by the Fixed CRRs alone from the simultaneous feasibility test is shown in Table 7.6. The column named Total Number Overloads list the total number of unique overloads resulting from the SINTO, NO-SINTO, and SINTO SFT. For instance, if there was an overload created in the SINTO SFT on line A-B and two overloads in the NO-SINTO on lines A-B and C-D and three overloads from the CHIMPO SFT on lines A-B, E-F, and G-H the total number of unique overloads would be equal to 4 (A-B, C-D, E-F, and G-H). The next column named

"No. Dissimilar Overloads" list the number of overloads that were not identified in all three SFT methods. The columns named CHIMPO, NOSINTO and SINTO identify which SFT method has the dissimilar overload. For example, in February there were 40 unique overloads among the three SFT methods. There was one dissimilar overload that did not appear in all three SFT method results. The dissimilar overload in February appeared in both the CHIMPO and the NOSINTO as indicated with the X in their column and in the February row.[4]

Table 7.6: Fixed CRRs overloads

		Dissimilar Overloads			
	Total Number Overloads	No. Dissimilar Overloads	CHIMPO	NOSINTO	SINTO
14-Jan	42	1	X		
14-Feb	40	1	X	X	
14-Mar	46	0			
14-Apr	18	1	X		
14-May	18	1	X	X	
14-Jun	17	1	X	X	
14-Jul	24	0			
14-Aug	11	0			
14-Sep	14	1	X	X	
14-Oct	27	1		X	
14-Nov	37	2	XX	X	
14-Dec	17	0			

In analyzing the table one, important and obvious observation is that the SINTO column contains no Xs. Resulting in no Xs indicates that the SINTO SFT was not as constrained as the NO-SINTO and CHIMPO SFT methods, although as previously mentioned they all model the same transmission outages but in different ways. If there was no Braess's paradox, then SINTO should have been more restrictive and

[4]Note: Expanding the limits may be different for each formulation therefore each auction might start the optimization at a different starting point (or condition).

should show all the violations that occur in the other models. This did not occur. This implies that some of the outages modeled exhibited the Braess's paradox effect and increased the transmission capacity such that the overload did not appear.

The second observation is that both the NO-SINTO and CHIMPO SFT infeasibilities results were the same in eight of the twelve months indicating that both approaches demonstrate similarities in identifying overloads caused by Braess's paradox not captured by the SINTO method.

7.3 Question 2: How were the auction results affected by Braess's paradox?

7.3.1 Effects on accepted quantities of bids

The primary objective of analyzing the auction results is to determine how the auction results based on different SFT approximations compare to each other using the ideal CHIMPO allocation as the benchmark for comparison. Revenue adequacy is attained by ensuring the CRR allocation is feasible during the market period, which in this case is the day-ahead market. Thus the focus of the analysis is on the bid (and offer) volumes awarded and not on the clearing prices for CRRs. Nevertheless, a price comparison for the bids that were accepted in one auction but not another is provided to determine which SFT approximation came closer to the CHIMPO formulation results, which most accurately reflects that actual distribution of outage conditions.

The simulation results data used to answer the question on how the auction results were affected by Braess's paradox are based on the cleared (awarded) bids and offers; these quantities are likely to be different among the four formulations. If any cleared bid or offer has a different megawatt quantity than the other three, it is included in the study data for the subsequent analysis. For example, if the awarded quantity for one particular right using the SINTO approximation is 5 MW and the other three methods (CHIMPO, NO-SINTO and NO) have a quantity of 0 MW for the same bid, then that right is included in the data set. Thus, any rights with unequal awards are included in the data set. Table 7.7 lists the bid and offer data quantities for each month. The first column starting at the left side of the table lists the simulated month. The second column with the heading, "Count," lists the total number of dissimilar bids (and offers). The cells in that column use conditional formatting where green indicates a lower value, yellow an intermediate value, and red color indicating a high value. The month with the smallest number of dissimilar bids is August, and the largest is April. The next column, which is entitled, "Total No. Bids," lists the total number of bids (and offers) submitted by auction participants for that auction. The fourth column named, "Total Fixed Bids" gives the number of previously allocated bids from earlier semi-annual auctions where the quantity of the awards has to be modeled in the monthly auction. Fixed bids were explained in Section 6.3.4. The fifth column with the heading entitled, "Total All Bids" is the sum of the "Total No. Bids" and "Total Fixed Bids." The last column entitled, "% of Bids Affected," is the percentage of dissimilar bids in the "Count" column to the total number of submitted bids in the "Total No. Bids" column. The column uses the same conditional formatting used in the Count column.

Table 7.7: Dissimilar awarded quantities among all four CRR auction models

Month	Count	Total No. Bids	Total Fixed Bids	Total All Bids	% of Bids Affected
Jan-14	3278	145340	19492	164832	2.3%
Feb-14	3874	127175	19457	146632	3.0%
Mar-14	3514	123444	19942	143386	2.8%
Apr-14	7776	146179	19816	165995	5.3%
May-14	6041	135708	20050	155758	4.5%
Jun-14	5002	154060	20838	174898	3.2%
Jul-14	4338	149985	24889	174874	2.9%
Aug-14	1677	155636	24625	180261	1.1%
Sep-14	3274	153793	23771	177564	2.1%
Oct-14	5252	141261	23230	164491	3.7%
Nov-14	6264	142456	22926	165382	4.4%
Dec-14	5827	129574	22425	151999	4.5%
Average	4676	142051	21788	163839	3.3%

As previously explained, the CHIMPO formulation results are the benchmark for comparison of the auction results. The first item analyzed to determine how the auction results are affected is the total megawatt quantities of the cleared dissimilar bids which are listed in Table 7.8. Here the total includes the sum (positive) values of cleared bids and offers. Conditional formatting is applied to each row where the color gradient is green for lower values and red for higher values. This same color scheme is used in all the subsequent tables below. Intuitively the first observation is that the

Normally Operated (NO) formulation results have a larger cleared megawatt volume than the other three formulation approaches. This is expected since the NO simulation does not include planned transmission outages and should have more available transmission capacity unless Braess's paradox has a very strong effect. Also notice that in August the volume was less for the NO than both the CHIMPO and SINTO suggesting the presence that Braess's paradox impacted the results (*i.e.*, transmission outages made more capacity available), which is consistent with the objective function value results of Section 7.2.3.4, above. A second observation is the SINTO results have more yellow coloring than both the CHIMPO and NO-SINTO results indicating that SINTO did not provide the most conservative volume. On the other hand, the CHIMPO and NO-SINTO are shaded mostly green indicating that they were closer in megawatt volume to each other than the SINTO volume. The fact that NO-SINTO and SINTO did not have the same volumes is evidence of Braess's paradox, in that, if the "no outages" network is indeed a looser set of constraints than networks with outages, adding the "no outages" network to SINTO should not have reduced the MW awarded. But in fact, it did, indicating that some networks with outages are actually less constraining than the no outages network, a manifestation of Braess's paradox.

7.3.2 Hypothesis test

In this section, the qualitative observation of the previous subsection is confirmed by undertaking hypothesis tests using the dissimilar cleared bid volume data set described in the previous subsection. In particular, a hypothesis test is conducted between the CHIMPO and NO-SINTO to determine if the difference is statistically significant. And likewise, the hypothesis test is used to determine if the difference between CHIMPO and SINTO values are also statistically significant.

Table 7.8: Comparison total quantity (MWs) awarded

	CHIMPO	NOSINTO	SINTO	NO
Jan-14	16927	17164	18082	20314
Feb-14	17291	16859	17511	22488
Mar-14	15214	15052	15456	19984
Apr-14	28150	27778	28714	37650
May-14	18722	19337	20834	26317
Jun-14	19215	19315	18319	23475
Jul-14	14587	14068	15151	16085
Aug-14	9391	8610	9424	9011
Sep-14	12107	11867	12300	15500
Oct-14	16209	16207	16297	23183
Nov-14	18095	19311	19900	29784
Dec-14	21365	21543	23042	27455
Average	17273	17259	17919	22604

7.3.2.1 Are the CHIMPO Total Awarded Bid Quantities equal to NO-SINTO Total Awarded Bid Quantities?

In this comparison, the awarded amounts for the NO-SINTO and CHIMPO auction simulations are compared to each other to determine whether they are statistically the same. The results of this hypothesis test is one of the considerations as to whether the simpler NO-SINTO model is sufficiently similar to the CHIMPO model so that NO-SINTO can be used to run the CRR auctions rather than the computationally more challenging CHIMPO model. This is one of several considerations analyzed in this chapter to determine whether the NO-SINTO can be utilized instead of the CHIMPO model. The hypothesis test follows. Let d be defined as the difference between the CHIMPO awarded bid quantities and the NO-SINTO awarded bid quantities.

$$d = \text{CHIMPO Awarded Quantities} - \text{NO-SINTO Awarded Quantities}$$

The null hypothesis is that the difference d is equal to zero or stated differently that the CHIMPO Awarded Quantities is equal to the NO-SINTO Awarded Quantities.

$$H_0 : d = 0$$

The alternative hypothesis is that the difference d is not equal to zero or that the CHIMPO Awarded Quantities are not equal to CHIMPO Awarded Quantities.

$$H_a : d \neq 0$$

The calculated d value is shown in the column labeled "Diff. (CHIMPO - NOSINTO)" of Table 7.9 and the sign of the difference is displayed in the column labeled "Sign."

Table 7.9: Hypothesis Sign Test: CHIMPO – NO-SINTO Awarded Quantities

Yr-Mo	CHIMPO	NOSINTO	Diff. (CHIMPO - NOSINTO)	Sign
14-Jan	16,927	17,164	(237)	-
14-Feb	17,291	16,859	432	+
14-Mar	15,214	15,052	162	+
14-Apr	28,150	27,778	372	+
14-May	18,722	19,337	(615)	-
14-Jun	19,215	19,315	(100)	-
14-Jul	14,587	14,068	519	+
14-Aug	9,391	8,610	781	+
14-Sep	12,107	11,867	240	+
14-Oct	16,209	16,207	2	+
14-Nov	18,095	19,311	(1,216)	-
14-Dec	21,365	21,543	(178)	-
Average	17,273	17,259	Count (+)	7
			Count (-)	5

The number of positive signs is equal to 7 and number of negative signs is equal to 5. The corresponding p-value from Table 7.2 for a 2-tail test with 7 positive signs is equal to 0.77441.

The result is not statistically significant since the p-value is more than the alpha value of 0.05 thus the test fails to reject the null hypothesis and the alternative hypothesis is rejected. This signifies that the CHIMPO awarded bid quantities are statistically indistinguishable from the NO-SINTO awarded bid quantities. This result indicates that the first condition is met in determining if the NO-SINTO model is a better approximation for the ideal CHIMPO model than the SINTO.

In the next section, a similar hypothesis test is used to determine whether the CHIMPO total awarded bid quantities are statistically equal to the SINTO total awarded bid quantities.

7.3.2.2 Is the CHIMPO Total Awarded Bid Quantities equal to SINTO Total Awarded Bid Quantities?

From the preceding section, the CHIMPO awarded bid quantities are statistically indistinguishable from the NO-SINTO, so the next test determines whether the same is true between the CHIMPO awarded bid quantities and the SINTO awarded bid quantities. The goal is to continue to analyze how are the auction results from the different models affected by Braess's paradox and to determine which model (NO-SINTO and SINTO) is a better approximation for the CHIMPO model. The hypothesis test follows. Let d be defined as the difference between the CHIMPO awarded bid quantities and the SINTO awarded bid quantities.

$$d = \text{CHIMPO Awarded Quantities} - \text{SINTO Awarded Quantities}$$

The null hypothesis is that the difference is equal to zero or stated differently that the CHIMPO Awarded Quantities is equal to the SINTO Awarded Quantities.

$$H_0 : d = 0$$

The alternative hypothesis is that the difference d is less than zero or that the CHIMPO Awarded Quantities are less than to SINTO Awarded Quantities which would be consistent with Braess's paradox affecting the results.

$$H_a : d < 0$$

The calculated d value is shown in the column labeled "Diff. (CHIMPO - SINTO)" of Table 7.10 and the sign of the difference is displayed in the column labeled "Sign."

Table 7.10: Hypothesis Sign Test: CHIMPO – SINTO Awarded Quantities

Yr-Mo	CHIMPO	SINTO	Diff. (CHIMPO - SINTO)	Sign
14-Jan	16,927	18,082	(1,155)	-
14-Feb	17,291	17,511	(220)	-
14-Mar	15,214	15,456	(242)	-
14-Apr	28,150	28,714	(564)	-
14-May	18,722	20,834	(2,112)	-
14-Jun	19,215	18,319	896	+
14-Jul	14,587	15,151	(564)	-
14-Aug	9,391	9,424	(33)	-
14-Sep	12,107	12,300	(193)	-
14-Oct	16,209	16,297	(88)	-
14-Nov	18,095	19,900	(1,805)	-
14-Dec	21,365	23,042	(1,677)	-
Average	17,273	17,919	Count (+)	1
			Count (-)	11

The number of positive signs is equal to 1 and number of negative signs is equal to 11. The corresponding p-value from Table 7.2 for a 2-tail test with 1 positive sign is equal to 0.00635.

The result is statistically significant since the p-value is less than the alpha value of 0.05; thus the test failed to accept the null hypothesis, and the alternative hypothesis is accepted. This signifies that the CHIMPO awarded bid quantities are statistically less than the SINTO awarded bid quantities. This implies that the CHIMPO model is more constraining than the SINTO model and that the difference in the total awarded quantities is statistically significant.

The hypothesis for the awarded quantities support the observations from the conditionally formatted Table 7.8 in that the CHIMPO auction cleared quantities are less that the SINTO but are statistically equal to the NO-SINTO cleared bid quantities.

7.3.3 Test of correlations

Now that the cleared bid quantity totals are compared, an analysis is performed of the tendency of the bids to vary together. In particular, the Pearson (product-moment correlation) coefficient correlations are used to compare the NO-SINTO, SINTO and NO formulation cleared bid megawatt results to the CHIMPO's results (*e.g.*, the CHIMPO versus NO-SINTO, CHIMPO versus SINTO, and CHIMPO versus NO correlations).

If the NO-SINTO results are more highly correlated to CHIMPO than are the other approximate models (SINTO and NO), then this is additional evidence that NO-SINTO is the better approximation. Table 7.11 lists the monthly correlation results. The correlation table uses the same row conditional formatting as described for the Table 7.8. In this case, a red color indicates the closest (highest) correlation. By observing the coloring, the cleared bid megawatt quantities that most closely matched the CHIMPO awarded megawatt quantities are the NO-SINTO bid quantities because it has the largest correlation values in nine out of the twelve months. As expected, the NO formulation results have the smallest correlation to the CHIMPO awarded bid quantities. A hypothesis test is performed to determine if the differences among these correlations are statistically significant.

Table 7.11: Correlations of approximate auction awarded quantities in three approximate models to awarded quantities in CHIMPO model

	NOSINTO	SINTO	NO
Jan-14	0.97971	0.97164	0.77624
Feb-14	0.9644	0.9534	0.48351
Mar-14	0.90035	0.98251	0.77295
Apr-14	0.92663	0.92065	0.26719
May-14	0.92331	0.86611	0.47312
Jun-14	0.96056	0.72903	0.72204
Jul-14	0.95912	0.8339	0.78439
Aug-14	0.93197	0.99939	0.89858
Sep-14	0.9471	0.99493	0.42603
Oct-14	0.93104	0.84936	0.53642
Nov-14	0.93774	0.80929	0.28494
Dec-14	0.99369	0.90294	0.78449
Average	0.9463	0.90109	0.60083

7.3.3.1 Are NO-SINTO or SINTO results more closely correlated to CHIMPO results?

Let d be defined as the difference between the NO-SINTO correlation values and the SINTO correlation values.

d = CHIMPO/NO-SINTO correlation values − CHIMPO/SINTO correlation values

The null hypothesis is that the difference d is less than equal or to zero or that the

CHIMPO/NO-SINTO correlation values are less than or equal to CHIMPO/SINTO correlation values.

$$H_0 : d \leq 0$$

The alternative hypothesis is that the difference d is greater than zero or stated differently that the CHIMPO/NO-SINTO correlation values are greater than the CHIMPO/SINTO correlation values.

$$H_a : d > 0$$

The calculated d value is shown in the column labeled "Diff. (NOSINTO - SINTO)" of Table 7.12 and the sign of the difference is displayed in the column labeled "Sign."

Table 7.12: Hypothesis Sign Test: CHIMPO/NO-SINTO – CHIMPO/SINTO Correlation Values

Yr-Mo	CHIMPO/NOSINTO	CHIMPO/SINTO	Diff. (CHIMPO/NOSINTO - CHIMPO/SINTO)	Sign
14-Jan	0.9797	0.9716	0.0081	+
14-Feb	0.9644	0.9534	0.0110	+
14-Mar	0.9003	0.9825	(0.0822)	-
14-Apr	0.9266	0.9206	0.0060	+
14-May	0.9233	0.8661	0.0572	+
14-Jun	0.9606	0.7290	0.2315	+
14-Jul	0.9591	0.8339	0.1252	+
14-Aug	0.9320	0.9994	(0.0674)	-
14-Sep	0.9471	0.9949	(0.0478)	-
14-Oct	0.9310	0.8494	0.0817	+
14-Nov	0.9377	0.8093	0.1285	+
14-Dec	0.9937	0.9029	0.0907	+
Average	0.9463	0.9011	Count (+)	9
			Count (-)	3

The number of positive signs is equal to 9 and number of negative signs is equal to 3. The corresponding p-value from Table 7.2 for a 1-tail test with 9 positive signs is equal to 0.07300.

The result is significant since the p-value is greater than the alpha value of 0.05 thus the null hypothesis is accepted, and the alternative hypothesis is rejected. This signifies that the NO-SINTO results are significantly closer to the correlation values to CHIMPO's awarded bid quantities compared to the difference between SINTO and CHIMPO results values. This indicates that the NO-SINTO awarded bid quantities vary together more closely than the SINTO awarded bid quantities, and so NO-SINTO is a better approximation of CHIMPO results than SINTO.

7.3.4 Test of RMSE

The last item examined to assess how the auction results were affected is to analyze the Root-Mean-Square-Error (RMSE) between each of the three approximate formulation's awarded megawatt bid quantities (NO-SINTO, SINTO, and NO) compared to the CHIMPO awarded bid megawatt quantities. Table 7.13 shows the RMSE values for the awarded megawatt bid quantities. In this case, a lower RMSE is desirable because it indicates less error between the awarded bid quantities. The conditional formatting is across each row and is the same as previously described.

The first observation is as expected that the NO formulation awarded bid quantities has the largest RMSE values relative to the CHIMPO awarded bid quantities. As before, this expectation arises because NO imposes no transmission outages in the

SFT. The next observation is that nine of twelve of the CHIMPO/SINTO RMSE values are larger than the CHIMPO/NO-SINTO values. Like Section 7.13, this supports the hypothesis that CHIMPO cleared bid megawatt volumes are closer to NO-SINTO values than to the SINTO cleared bid megawatt volumes.

Table 7.13: RMSE of approximate auction awarded quantities in three approximate models to awarded quantities in CHIMPO model

	NOSINTO	SINTO	NO
Jan-14	4.00446	4.7574	15.0988
Feb-14	3.57378	4.16306	16.1974
Mar-14	7.4776	2.98652	12.3698
Apr-14	3.71742	3.88251	15.3673
May-14	4.41221	6.02467	12.625
Jun-14	3.61018	9.46529	10.2644
Jul-14	2.88392	5.91162	7.16526
Aug-14	6.8376	0.64499	8.31479
Sep-14	6.46241	1.70034	18.4344
Oct-14	3.65346	5.35537	11.0452
Nov-14	3.61403	6.07887	17.5975
Dec-14	2.11382	8.04506	13.4977
Average	4.36341	4.91798	13.1648

As an index of the strength of that conclusion, a hypothesis test can be performed to confirm whether the CHIMPO/NO-SINTO RMSE values are significantly smaller than the CHIMPO/SINTO values.

7.3.4.1 Are the CHIMPO/NO-SINTO RMSE values less than the CHIMPO/SINTO RMSE values for the awarded bids?

Let d be defined as the difference between the CHIMPO/NO-SINTO quantities RMSE values and the CHIMPO/SINTO RMSE values.

$$d = \text{CHIMPO/NO-SINTO RMSE values} - \text{CHIMPO/SINTO RMSE values}$$

The null hypothesis is that the difference d is less than or equal to zero or that the CHIMPO/NO-SINTO RMSE values are less than or equal to CHIMPO/SINTO RMSE values.

$$H_0 : d \leq 0$$

The alternative hypothesis is that the difference d is greater than zero or stated differently that the CHIMPO/NO-SINTO RMSE values are greater than the CHIMPO/SINTO RMSE values.

$$H_a : d > 0$$

The calculated d value is shown in the column labeled "Diff. (NOSINTO - SINTO)" of Table 7.14 and the sign of the difference is displayed in the column labeled "Sign."

The number of positive signs is equal to 3 and number of negative signs is equal to 9. The corresponding p-value from Table 7.2 for a 1-tail test with 3 positive signs

Table 7.14: Hypothesis Sign Test: CHIMPO/NO-SINTO – CHIMPO/SINTO RMSE Values

Yr-Mo	CHIMPO/NOSINTO	CHIMPO/SINTO	Diff. (CHIMPO/NOSINTO - CHIMPO/SINTO)	Sign
14-Jan	4.0045	4.7574	(0.7529)	-
14-Feb	3.5738	4.1631	(0.5893)	-
14-Mar	7.4776	2.9865	4.4911	+
14-Apr	3.7174	3.8825	(0.1651)	-
14-May	4.4122	6.0247	(1.6125)	-
14-Jun	3.6102	9.4653	(5.8551)	-
14-Jul	2.8839	5.9116	(3.0277)	-
14-Aug	6.8376	0.6450	6.1926	+
14-Sep	6.4624	1.7003	4.7621	+
14-Oct	3.6535	5.3554	(1.7019)	-
14-Nov	3.6140	6.0789	(2.4648)	-
14-Dec	2.1138	8.0451	(5.9312)	-
Average	4.3634	4.9180	Count (+)	3
			Count (-)	9

is equal to 0.07300.

The result is not significant since the p-value is greater than the alpha value of 0.05 so the test fails to reject the null hypothesis and the alternative hypothesis is rejected. This signifies that the CHIMPO/NO-SINTO RMSE values are statistically less than the CHIMPO/SINTO RMSE values.

7.3.5 Comparison of CRR prices of NO, SINTO, NO-SINTO with CHIMPO

Thus far, the cleared bid quantities have been analyzed to examine how the bid results were affected. Below the prices of the dissimilar bid quantities are analyzed because the prices may be different for cleared bids of the same volumes. The change in price is an indication of how the SINTO approach impacts all the other bidders not just in bid volume differences but also more broadly the prices auction participants pay for the bids. A second objective is to see which formulation had prices that most closely resembled the CHIMPO cleared prices for dissimilar bids – in particular, whether the NO-SINTO model is a good approximation.

The first bid price item examined is the price correlation of the dissimilar bids for each of the three formulations (NO-SINTO, SINTO and NO) relative to the CHIMPO cleared dissimilar bid prices. Table 7.15 list the price correlations of the NO-SINTO, SINTO and NO price results to the CHIMPO price results. The conditional formatting is as previously described where the green coloring represents the lowest value, and the highest is colored red.

Using this color gradient, the first observation to note is that the CHIMPO/NO price correlations are always smaller than the CHIMPO/NO-SINTO price correlation values and mostly smaller than the CHIMPO/SINTO values. The second observation is that the CHIMPO/NO-SINTO price correlation values are mostly greater than the CHIMPO/SINTO correlations. This indicates that the NO-SINTO prices of the awarded bids tend to vary more similarly to the CHIMPO prices than do the SINTO and NO prices.

The RMSE associated with the cleared bid prices is the last item analyzed to answer: how were the auction results affected. Table 7.16 list the RMSE values for the auction simulations. The conditional formatting is the same as the one throughout

Table 7.15: Correlations of clearing prices in three approximate models to awarded quantities in CHIMPO model

	NOSINTO	SINTO	NO
Jan-14	0.99968	0.9993	0.84219
Feb-14	0.99985	0.99949	0.93261
Mar-14	0.99495	0.99995	0.76939
Apr-14	0.99687	0.99725	0.75496
May-14	0.99806	0.99431	0.86519
Jun-14	0.99857	0.73457	0.98623
Jul-14	0.9996	0.90186	0.98683
Aug-14	0.99861	1.00000	0.99554
Sep-14	0.99983	0.99997	0.9874
Oct-14	0.99963	0.99591	0.93851
Nov-14	0.99969	0.99965	0.90564
Dec-14	0.99954	0.9817	0.87839
Average	0.99874	0.967	0.90357

the chapter. The main observations are that the price error values compared to the CHIMPO prices are mostly smaller for the NO-SINTO than the SINTO prices errors and the NO price errors are greater than both the SINTO and NO-SINTO prices.

7.3.6 Summary of comparison of auction results

The preceding results shows that there is agreement among the comparative analyses (total quantities awarded, correlations and RMSE) which indicates the following:

- The NO auction allocation results are indeed less constrained so that more bids/offers are accepted, and the results are more different from CHIMPO that are the NO-SINTO and SINTO results. This is an intuitive result since the NO

Table 7.16: RMSE of clearing prices in three approximate models to awarded quantities in CHIMPO model

	NOSINTO	SINTO	NO
Jan-14	10.1615	14.7126	226.188
Feb-14	7.69363	14.2716	163.555
Mar-14	54.7687	5.63289	351.131
Apr-14	70.7045	66.7904	572.05
May-14	46.6933	78.1184	389.987
Jun-14	71.1798	823.543	204.783
Jul-14	28.4697	434.852	160.745
Aug-14	19.606	1.12185	34.2171
Sep-14	5.67181	2.36367	50.058
Oct-14	12.6235	42.2858	161.008
Nov-14	16.5692	17.8217	347.808
Dec-14	9.35867	61.4928	150.152
Average	29.4584	130.251	234.307

can be perceived to be less constrained because it does not include outages.

- The SINTO auction allocation results cleared with greater volumes than both the CHIMPO and NO-SINTO models. This shows that the SINTO SFT allocation is not as conservative as the CHIMPO and NO-SINTO allocations. This also indicates that the SINTO allocation would not be simultaneously feasible in the transmission configurations modeled in CHIMPO. It also suggests some outages exhibited Braess's paradox such that the NO-SINTO and CHIMPO SFTs are more constrained than the simultaneous imposition of all outages, which in the absence of Braess's paradox would be more constraining.

- The NO-SINTO allocation total awarded bid quantity, the pattern of awarded quantities, and prices were closer to the ideal CHIMPO than to the SINTO model results. These results show that the NO-SINTO is a better approximation to CHIMPO than the SINTO approximation.

7.4 Question 3: Did the proposed formulations reduce the effects of Braess's paradox and SINTO?

As explained in Section 7.2, the explicit identification of outages that cause Braess's paradox is challenging in a large network with many flows. This is because the identification of a Wheatstone bridge circuit is not enough to guarantee Braess's paradox will occur; furthermore, there are thousands of contingencies that are also analyzed to solve the optimization problem. Therefore, the case study in this thesis instead relies on more indirect evidence that Braess's paradox affected the allocation results. One main indication used in this case study is to determine if the objective function value of the SINTO approach has a lower value than both the CHIMPO and NO-SINTO values given the same outages modeled in all three formulations (NO-SINTO, CHIMPO, and SINTO). If so, then the SINTO approach would suppress higher value bids, be more conservative, and would yield a set of awarded bids that would be feasible in both the CHIMPO and NO-SINTO topologies. However, the results indicate that the SINTO objective function values were not lower than both the other formulations indicating that a set of higher value bids were not awarded and were constrained.

Take for example, that in the NO-SINTO the only circuit added compared to the SINTO was the normally operated (NO) system transmission configuration without outages. If the SINTO approach is considered the most conservative, then it would not be expected that adding constraints from a less constrained topology would impact the results. It was found that the SINTO allocation based on the concept of the simultaneous feasibility test would not be feasible in the normally operated transmission topology with no scheduled outages, which is evidence of Braess's paradox. When the outages were modeled according to their actual transmission outage schedules (CHIMPO), the associated topologies modeled in the simultaneous feasibility test also would be feasible with the SINTO allocation otherwise the CHIMPO objective function values would not be lower than the SINTO objective function values. A second indication is to analyze the bids to see which set of bids were closer to the CHIMPO results. Once again the SINTO results did not compare as well as the NO-SINTO SFT. Thus, by the evidence, both the CHIMPO and NO-SINTO reduced the effects of Braess's paradox for transmission outages that start or end or do both within the time-frame of the period modeled.

7.5 Question 4: Which formulation better approximates CHIMPO, and why?

The main advantage of the CHIMPO formulation is that it most accurately reflects the time sequence of the actual unique transmission configurations resulting from the scheduled planned transmission outages. Revenue inadequacy occurs due to differences in the transmission system topology used in the SFT for the CRR (FTR) allocation process and the transmission system topology used to calculate the LMPs in the day-ahead energy market. For this reason,[5] the CHIMPO formulation is used as the ideal allocation model. However, the CHIMPO model is much larger and thus likely to be harder to solve, as discussed in Section 5.2. This being the case, the objective of this question is to see which of the more compact formulation approximations (NO-SINTO or SINTO) comes closest to the ideal CHIMPO allocation.

This can be assessed by considering the objective function values, MW CRR awards, and prices of those awards. In this section, the relevant comparisons made in Section 7.2 and 7.3 are used to draw conclusions about this question. To begin, the OFVs in Table 7.1 are again analyzed. From observing the color gradient, the NO-SINTO OFVs are mostly shaded green like the CHIMPO OFVs visually implying that they both are similar and of lower value than the SINTO OFVs which are mostly shaded yellow with June being red and July being brown which are both indicating

[5] This is under the assumption that the outages occur as scheduled and no new outages happen.

higher values than the yellow colored cells. A sign nonparametric hypothesis test follows to confirm the visual observation and to determine if the values are statistically significant.

7.5.1 OFV hypothesis testing 2

7.5.1.1 Is SINTO's OFV equal to CHIMPO's OFV?

A two-tailed Sign Test was previously performed in Section 7.2.3.2 to determine whether the SINTO OFVs were greater than the CHIMPO OFV. The Sign Test resulted in rejecting the null hypothesis that the difference between SINTO and CHIMPO OFVs was equal to zero and accepted the alternative hypothesis that the difference was a positive value. This result provided statistical evidence that the difference between the SINTO OFV and CHIMPO OFV happened not by chance.

7.5.1.2 Is NO-SINTO's OFV equal to CHIMPO's OFV?

Let d be defined as the difference between the NO-SINTO OFV and CHIMPO OFV.

$$d = \text{NO-SINTO OFV} - \text{CHIMPO OFV}$$

The null hypothesis is that the difference d is equal to zero or stated differently that the NO-SINTO OFV is equal to the CHIMPO OFV.

$$H_0 : d = 0$$

The alternative hypothesis is that the difference d is greater than zero or that the SINTO OFV is greater than the CHIMPO.

$$H_a : d > 0$$

The calculated d value is shown in the column labeled "Diff. (NO_SINTO - CHIMPO)" of Table 7.17 and the sign of the difference is displayed in the column labeled "Sign."

Table 7.17: Hypothesis Sign Test: NO-SINTO and CHIMPO OFV

Yr-Mo	NOSINTO	CHIMPO	Diff. (NOSINTO - CHIMPO)	Sign
14-Jan	18,838,810	18,813,774	25,036	+
14-Feb	17,308,897	17,314,282	(5,385)	-
14-Mar	23,729,965	23,858,408	(128,443)	-
14-Apr	26,618,446	26,615,233	3,213	+
14-May	39,298,710	39,067,548	231,162	+
14-Jun	40,965,938	40,950,764	15,174	+
14-Jul	46,504,649	46,634,780	(130,131)	-
14-Aug	37,867,188	38,009,087	(141,899)	-
14-Sep	31,538,607	31,552,409	(13,802)	-
14-Oct	29,197,910	29,180,333	17,577	+
14-Nov	28,834,513	28,768,425	66,088	+
14-Dec	25,726,435	25,691,370	35,065	+
Average	30,535,839	30,538,034	Count (+)	7
			Count (-)	5

The number of positive signs is equal to 7 and number of negative signs is equal to 5. The corresponding p-value from Table 7.2 for a 2-tail test with 7 positive signs is equal to 0.77441.

The result is not significant since the p-value is greater than the alpha value of 0.05 thus the test fails to reject the null hypothesis and the alternative hypothesis is rejected. This signifies that the NO-SINTO OFVs are statistically indistinguishable from the CHIMPO OFVs.

Based on the OFV hypothesis Sign Test results, the SINTO OFVs were statistically greater than the CHIMPO OFVs and the NO-SINTO OFVs were statistically equal to the CHIMPO providing evidence that the NO-SINTO OFVs values are a closer approximation to the CHIMPO OFV than the SINTO OFV.

7.6 Question 5: Can the proposed formulations be practically implemented?

Computational performance is a key consideration in the successful implementation of optimization software. ERCOT CRR auctions (like FTR auctions in other RTOs) are conducted in accordance with a specified schedule set by the ERCOT protocols [160]. The schedule dedicates time and deadlines for all activities to occur. For example, it establishes market participant CRR bid submission deadlines by specifying when the CRR bidding window opens and when it closes. To that end, there is limited time for the ERCOT's CRR engineers to perform the necessary tasks to conduct the auction which must also take into account the time to sufficiently analyze and validate the CRR results. Besides, the time span must allow sufficient time for ERCOT's CRR engineers to rerun the auction in the event problems occur; for instance if the auction model run fails due to technical issues. Thus, computational performance is an important consideration because any increases in computational time reduce the provisions made for managing unforeseen CRR auction issues.

Table 7.18 displays the relative run-time for the case study simulations expressed as a percentage of SINTO's run-time since SINTO CRR auction methodology is the current practice.[6] As expected due to the additional sets of constraints from various topologies modeled, the CHIMPO model runs has the largest run-time with a minimum run-time percentage increase of 231% and a maximum of 1309% realized in July and December, respectively, compared to SINTO.

Table 7.18: Model relative percent run-time comparison

	SINTO	NOSINTO	CHIMPO
Jan-14	100%	132%	710%
Feb-14	100%	146%	486%
Mar-14	100%	139%	496%
Apr-14	100%	131%	872%
May-14	100%	156%	829%
Jun-14	100%	148%	724%
Jul-14	100%	146%	231%
Aug-14	100%	135%	527%
Sep-14	100%	133%	247%
Oct-14	100%	124%	677%
Nov-14	100%	156%	1288%
Dec-14	100%	126%	1309%
Average	100%	139%	700%

The second observation is that CHIMPO's run-time relative to SINTO varies greatly due to the number of topologies modeled. The NO-SINTO method run-times are much lower and more consistent (vary less) than the CHIMPO run-times, relative

[6]The actual run-times are not presented for proprietary reasons.

to SINTO run-times. The NO-SINTO run-times ranged from a minimum of 124% in October to 156% in both May and November. To confirm this observation, the coefficient of variation (CV) is compared for each model approach and shown in Table 7.19. The coefficient of variation is calculated by dividing the standard deviation of SFT model (SINTO, NO-SINTO, and CHIMPO) run-times by the mean of the SINTO run-times.

$$CV_{Model} = \frac{s_{Model}}{\bar{x}_{SINTO}}$$

where s equals the standard deviation and $\bar{x}$ is the mean.

Also shown in Table 7.19, is the relative percent coefficient of variation. The relative percent CV for NO-SINTO is only 29% larger than SINTO whereas the relative percent CV for the CHIMPO is larger than 20 times larger than the SINTO.

$$CV_{\text{Percentage to SINTO}} = \frac{CV_{Model}}{CV_{SINTO}} \times 100\%$$

Table 7.19: Model run-times coefficient of variation comparison

	SINTO	NOSINTO	CHIMPO
Coefficient of Variation (CV)	0.1014	0.1311	2.0441
Relative Percent CV	100%	129%	2016%

Another important aspect to consider in implementing either the NO-SINTO or CHIMPO CRR auction solutions is the incremental data preparation work and model set-up work. The CHIMPO approach would require an additional topology pre-processing application to create a set of power flow base cases for each unique transmission configurations derived from the transmission outage schedules that the auction software converts into a corresponding set of constraints. Further, the auction software would have to reconfigured to enable it to assemble and process the additional data input sets required. This increases the complexity of preparing the auction model and the size of the model input data required. At a minimum, it is another step in the overall process whose potential to fail adds an incremental risk. Conversely, the NO-SINTO approach is much easier to implement than the CHIMPO because the only additional data set is one power flow base case that omits the planned outages. It also has minimal model configuration changes to accommodate the additional set of constraints.

Implementing the CHIMPO methodology for the ERCOT CRR auction would be challenging and unlikely to be successful due to much longer run-times that vary considerably with the fluctuating sets of topology constraints. For example, if an issue occurred that required a single re-run for the simulated December auction, it might require twenty-six times the amount of time to do a single SINTO run.[7] In addition, the additional data preparation required and model configuration necessary creates another obstacle to practical implementation. On the contrary, the NO-SINTO approach is more implementable due to its relatively modest increase in run-time that on average increases the SINTO run-time by 39% and minimal increase in data preparation and model configuration work.

[7] If the RTO adopted a minimum of one transmission configuration a day then the maximum set of modeled topologies to create the transmission constraints can increase to 31. The number of topologies to create the December simulation was 18, see Table 6.3.

One advantage that the CHIMPO CRR formulation has that is not observed from the case study findings is that CHIMPO formulation, unlike the SINTO and NO-SINTO formulations, can model all the transmission outages. As previously explained in Section 6.5, ERCOT CRR auction engineers select a subset of the transmission outages based on a day in that month that has the most coincidental transmission outages.[8] The case study used the transmission outages that ERCOT included in its actual CRR auction, so this potential advantage is not reflected in case study.

7.7 Improving NO-SINTO

In analyzing the NO-SINTO objective function values in Table 7.1, there are three months (March, August, September) where the NO-SINTO performance was worse than the SINTO OFVs in comparison to CHIMPO's OFVs. After analyzing the outage duration data in Table 7.20, it was observed that in March, 80% of the outages were month-long outages and August and September the percentage was 61% and 71%, respectively.

A hypothesis was formed whether the month-long outages exhibited Braess's paradox such that if the outage lasted a total month, then the normally operated in-service state of the outage would never occur in the CHIMPO constraints, whereas it is represented in the NO-SINTO normally operated topology constraints. Therefore if the

[8] One reason for adopting this practice is to prevent problems that create infeasible solution during contingency analysis in the SFT that could create electrical islands. Not modeling all the outages that reduce capacity in the CRR auction may also cause revenue inadequacy.

Table 7.20: Imposed transmission outage duration

	Imposed in Auction	Duration Month Long	Duration Partial Month	Full Month Percent	Partial Month Percent
Jan-14	36	18	18	50%	50%
Feb-14	36	28	8	78%	22%
Mar-14	54	43	11	80%	20%
Apr-14	62	41	21	66%	34%
May-14	46	14	32	30%	70%
Jun-14	33	15	18	45%	55%
Jul-14	25	22	3	88%	12%
Aug-14	28	17	11	61%	39%
Sep-14	31	22	9	71%	29%
Oct-14	58	39	19	67%	33%
Nov-14	74	27	47	36%	64%
Dec-14	66	37	29	56%	44%
Average	46	27	19	61%	39%

"no outages" case in NO-SINTO were modified to include outages that last the entire period, then the NO-SINTO model would perform better in terms of matching the CHIMPO results. A means of testing this hypothesis was developed in which the NO-SINTO is re-run by including all the month-long outages into the normally operated system topology constraints (which is the additional topology added to SINTO). This is so that the Braess's paradox effect arising from the difference between the normally operated no outage case and one with all month-long outages would not impact the solution. Previously, none of the month-long outages were included in the NO network constraints in the NO-SINTO model. The objective function results from the NO-SINTO are shown in the center column of Table 7.21 entitled "Adj NO-SINTO" together with the other formulation OFV results taken from Table 7.1. The conditional formatting is applied to the rows and is the same as used throughout this chapter. Based on the row coloring, it is observed that the adjustment results in closer NO-SINTO/CHIMPO OFVs for March, August, and September.

Table 7.21: OFV table with Adj NO-SINTO values

	OFV				
	CHIMPO	NO_SINTO	Adj NO_SINTO	SINTO	NO
Jan-14	18,813,774	18,838,810	18,825,053	18,868,647	19,629,762
Feb-14	17,314,282	17,308,897	17,316,569	17,356,073	18,069,044
Mar-14	23,858,408	23,729,965	23,861,214	23,890,777	24,345,686
Apr-14	26,615,233	26,618,446	26,624,904	26,636,015	32,259,907
May-14	39,067,548	39,298,710	39,087,382	39,466,758	43,006,401
Jun-14	40,904,656	40,965,938	41,037,833	42,791,244	42,213,034
Jul-14	46,634,780	46,504,649	46,634,236	47,022,576	47,343,031
Aug-14	38,009,087	37,867,188	38,008,781	38,010,900	38,018,944
Sep-14	31,552,409	31,538,607	31,553,650	31,559,941	32,388,375
Oct-14	29,180,333	29,197,910	29,205,067	29,385,808	30,771,810
Nov-14	28,768,425	28,834,513	28,849,237	28,969,378	30,650,288
Dec-14	25,691,370	25,726,435	25,701,657	25,907,119	27,131,620

To support this observation and determine if the Adjusted NO-SINTO solution improved the performance based on the concept that outages that exhibited Braess's paradox were being constrained in the NO-SINTO and not the CHIMPO, mean absolute error are calculated for the four formulations compared to CHIMPO's OFVs. Table 7.22 list the absolute errors for monthly auction simulations for each formulation approach OFVs compared to the CHIMPO OFVs. As can be seen from the table by comparing the NO-SINTO to the Adjusted NO-SINTO results, the absolute errors decreased for March from \$128,443 to \$2,805, August from \$141,899 to \$306, and September from \$13,802 to \$1,241. The average error (MAE) is listed at the bottom of the table and which shows that the Adjusted NO-SINTO has the lowest average error of $24,748 in comparison with the other auction formulations simultaneously feasibility tests (NO-SINTO, SINTO, and NO).

This result supports the hypothesis that if Braess's paradox is present for outages that last the entire period, then including a Normally Operated (no planned outage) case (which never actually occurs) would result in NO-SINTO over-constraining the auction, and could result in SINTO being closer than NO-SINTO to CHIMPO. An outage exhibiting Braess's paradox lasting the entire period will not be constrained in either the SINTO or CHIMPO models thus during those situations (where the month-long outages exhibit Braess's paradox) the SINTO model may result in a closer approximation to CHIMPO model than the NO-SINTO model. However, by simply including the month-long outages in the NO network constraints of the NO-SINTO model (Adjusted NO-SINTO), the NO-SINTO becomes a better approximation than before, and now more obviously better than SINTO. This is confirmed by the statistical analysis below.

The improvement in the NO-SINTO formulation and logic behind its hypothesis is based on the notion of Braess's paradox and while not a defined mathematical proof the practical application of the concept provides an indication that it works. In particular, the adjusted NO-SINTO formulation is better than the SINTO formulation in all twelve months, which is statistically significant, whereas the original NO-SINTO was better in only 9 of 12 months, which is not statistically significant. Comparing the

Table 7.22: Absolute Error OFV compared to CHIMPO including Adjusted NO-SINTO

	NO_SINTO	Adj NO_SINTO	SINTO	NO
Jan-14	25,036	11,280	54,873	815,989
Feb-14	5,385	2,287	41,791	754,763
Mar-14	128,443	2,805	32,369	487,278
Apr-14	3,213	9,671	20,782	5,644,674
May-14	231,161	19,833	399,209	3,938,853
Jun-14	61,282	133,178	1,886,588	1,308,378
Jul-14	130,131	544	387,796	708,251
Aug-14	141,899	306	1,813	9,857
Sep-14	13,802	1,241	7,531	835,966
Oct-14	17,578	24,734	205,475	1,591,478
Nov-14	66,088	80,812	200,953	1,881,863
Dec-14	35,066	10,287	215,750	1,440,251
MAE	**71,590**	**24,748**	**287,911**	**1,618,133**

two NO-SINTO models, the average absolute error is reduced by almost two-thirds by adjusting the model.

7.8 Summary of case study findings

The case study provides evidence that Braess's paradox effect impacts the allocation of CRRs. As intended and expected, the SINTO SFT indeed constrained the allocation when comparing its allocation to the NO SFT (a model with no outages) simulation allocation; however, did not prevent the increased capacity from outages that exhibit Braess's paradox from posing a revenue inadequacy risk. The presence of Braess's paradox is shown by the NO-SINTO SFT being more constraining than the SINTO SFT even though the only additional constraints added to the NO-SINTO formulation are for a topology that does not include outages. The better objective function for SINTO than for the more accurate CHIMPO model, which better represents the sequence of outages, indicates that Braess's paradox can over allocate financial transmission rights in that there will be a risk of revenue inadequacy in some hours. This difference in objective functions indicates that the SINTO allocation of rights is not feasible for some transmission configurations (with fewer outages) that occur during the month and are considered by CHIMPO. This provides implicit evidence that some of the outages exhibited Braess's paradox.

In this case study, the NO-SINTO auction results are closer to the ideal CHIMPO results than the SINTO. Thus the NO-SINTO approximation is closer to the allocation if the sequence of actual transmission configurations is modeled (CHIMPO) which may lead to less of a risk of revenue inadequacy than SINTO. If the "no outages" network that is added to SINTO in order to create NO-SINTO includes outages that occur for the entire month (and thus are always present in CHIMPO as well), then NO-SINTO results are even closer to CHIMPO's results. The inaccuracies of the NO-SINTO formulation appears small enough that its computational performance and decreased data needs strongly favors an NO-SINTO implementation over the full CHIMPO implementation. The CHIMPO computational time substantially increased with the number of topologies used to create the SFT transmission constraints. Indeed, due to this performance issue, CHIMPO is unlikely to be implemented in today's RTOs. Since the computational effort required for the SINTO and the NO-SINTO are similar but the latter is the much more accurate representation of the CHIMPO auction, the NO-SINTO formulation is recommended to be used rather than the current practice of using SINTO to allocate transmission rights.

Chapter 8

Summary and Future Research

8.1 Summary

The first objective of this thesis is to demonstrate that Braess's paradox in FTR auctions using the SINTO simultaneous feasibility test in combination with the term RTO's provide FTRs (calendar-strip) can in theory lead to revenue inadequacy. This is accomplished through a simple example presented in Chapter 4. The second objective is accomplished using this same example to demonstrate that the simultaneous imposition of non-coincidental outages in FTR auctions can create situations where combinations of outages exhibiting Braess's paradox may lead to a less constrained SFT that causes the overallocation of FTRs. The ERCOT case study in Chapters 6 and 7 also confirm that Braess's paradox is potentially significant in real CRR markets.

The third objective of this research is to develop two practical FTR auction formulations that can reduce or mitigate the Braess's paradox effect. In Chapter 5, two practical formulations that can be immediately implemented by RTOs are presented to remedy the issue. The CHIMPO approach reduces the impact of Braess's paradox and SINTO by creating constraints that accurately model the sequence of transmission configurations derived from the planned transmission outages and how they affect the feasibility of calendar strip-type FTRs. For this reason, the CHIMPO formulation is deemed the ideal solution and is used as the benchmark to compare two approximate models: the SINTO formulation (widely used by RTOs today) and the NO-SINTO formulation. The second of these formulations which is proposed for the first time in this thesis (the NO-SINTO FTR auction) simply adds one additional set of constraints to SINTO based on a transmission system configuration that does not include planned transmission outages or only includes those outages that last the entire duration of the transmission rights (*e.g.*, one month).[1] The NO-SINTO formulation takes advantage of the concept of Braess's paradox by adding a seemingly counter intuitive set of constraints to the SFT that prevents FTRs allocations from using the increased capacity caused by Braess's paradox.

The fourth objective is achieved through the ERCOT CRR auction case study in Chapters 6 and 7. Its goal is to determine which SFT method (SINTO or NO-SINTO) leads to an allocation that is closer to the ideal CHIMPO formulation. In this

[1] Adjusted NO-SINTO

comparison it is deduced through implicit means (*e.g.*, comparing objective function values and allocations) that some planned outages exhibit the Braess's paradox effect in the 2014 ERCOT monthly CRR auction outages that were not mitigated by the SINTO SFT. The objective function values (OFV) of both the CHIMPO OFVs and the NO-SINTO OFVs were lower than the SINTO OFVs, thus the SINTO approach does not achieve the conservative results desired. More importantly it means that the SINTO allocation is not feasible for at least some of the transmission configurations scheduled to occur during operations, thus SINTO does risk not accomplishing its intent of maintaining revenue adequacy.

Lastly, in Section 7.6, the fifth and final objective is to determine through testing the performance of the CHIMPO and NO-SINTO CRR auction approaches on realistically sized power networks to provide run-time comparisons for practical implementation by RTOs. The run-time performance of the NO-SINTO averaged over the twelve simulated months is approximately 39% greater than the SINTO average. The CHIMPO times varied greatly among the monthly simulations due to the number of topologies modeled, and the average percentage is 700% greater than SINTO's average. The recommendation based on this assessment for RTO implementation based on the computational run-times, CRR market deadlines and additional preparation work required suggest that NO-SINTO may be implemented to more accurately represent the feasibility of CRR allocations but the CHIMPO approach is unlikely to be practical in the near term.

8.2 Future research

The simultaneous feasibility test is crucial for managing revenue adequacy. The ideal simultaneous feasibility test applied to the FTR auction would constrain the FTR release to the capacity of the transmission system based on the resulting network configurations due to the scheduled outages. In this thesis, it is called the CHIMPO formulation. However, the CHIMPO formulation is, unfortunately, improbable to implement due to its long and varying run-times but, unlike the SINTO and NO-SINTO approximations, possesses the capacity of imposing all the operationally feasible outages. Both the SINTO and NO-SINTO approximations use a single topology to model the outages and therefore are limited in the number of outages they can model.

The first suggestion for future research is to develop a method to minimize the number of topologies needed to represent a set of scheduled outages without losing fidelity. For example, two outages occurring in different periods and that are electrically distant from each other (having no mutual impacts) can be combined into one topology without losing fidelity in the simultaneous feasibility capacity of the two topologies. Combining outages into a compressed set of topologies reduces the number of constraints modeled and improve the run-times of the CHIMPO approach.

One approach to reducing the number of topologies while preserving the fidelity of the model is to identify outages that are electrically independent of each other and grouping them into the same topology to reduce the set of topologies that represent the scheduled transmission outages. This problem is similar to the problem of quickening contingency analysis by identifying and reducing the number of monitored elements for each contingency. Methods analogous to concentric relaxation [102, 173] and bounding [102, 174] can be developed to determine the extent that a transmission outage affects the transmission system. Once this is known the outages whose, affected systems do not intersect can be combined to the same topology.

The second suggestion for future research is to perform additional testing of the Adjusted NO-SINTO approximation. The Adjusted NO-SINTO was developed in Section 7.7 to answer why, in a few months, the SINTO FTR approximation is closer to CHIMPO than to NO-SINTO. The intention of the additional Adjusted NO-SINTO simulations is to confirm the hypothesis that the month-long outages that exhibit Braesss paradox caused the Normal Operation topology constraints of the NO-SINTO approximation to deviate from the CHIMPO results. This conclusion is based solely on the objective function values.

Lastly, a final suggestion for future research is to study the impact of calendar strip FTR products. As shown in this thesis, FTRs awarded by calendar strips (validity period) using the SINTO FTR auction approximation may cause revenue inadequacy under certain conditions. In some cases, the calendar strip product is overly conservative and even if the CHIMPO formulation is used the quantity of FTRs released is determined by the topology with the least capacity. Reducing the validity period has advantages for the market participants in that it allows customized bidding (shaping) for renewable resources, hedge generators that plan to be on outage part of the month, make available more FTRs during less constrained periods which may increase auction revenues and hedging.

Bibliography

[1] Hogan, William, "Financial Transmission Right Formulations," *Report, Center for Business and Government, John F. Kennedy School of Government, Harvard University, Cambridge, MA*, 2002.

[2] Joskow, Paul L and others, *Lessons Learned from the Electricity Market Liberalization.* Massachusetts Institute of Technology, Center for Energy and Environmental Policy Research, 2008.

[3] Schweppe, Fred C and Caramanis, Michael C and Tabors, Richard D and Bohn, Roger E, *Spot Pricing of Electricity.* Springer Science & Business Media, 2013.

[4] Caramanis, Michael C and Bohn, Roger E and Schweppe, Fred C, "Optimal Spot Pricing: Practice and Theory," *IEEE Transactions on Power Apparatus and Systems*, no. 9, pp. 3234–3245, 1982.

[5] Bohn, Roger E and Caramanis, Michael C and Schweppe, Fred C, "Optimal Pricing in Electrical Networks over Space and Time," *The Rand Journal of Economics*, pp. 360–376, 1984.

[6] Chandley, John D, "A Standard Market Design for Regional Transmission Organizations," *The Electricity Journal*, vol. 14, no. 10, pp. 27–53, 2001.

[7] Benjamin, Richard, "A Two-Part Tariff for Financing Transmission Expansion," *Utilities Policy*, vol. 27, pp. 98–107, 2013.

[8] O'Neill, Richard P and Helman, Udi and Baldick, Ross and Stewart, WR and Rothkopf, Michael H, "Contingent Transmission Rights in the Standard Market Design," *IEEE Transactions on Power Systems*, vol. 18, no. 4, pp. 1331–1337, 2003.

[9] O'Neill, Richard P and Baldick, Ross and Helman, Udi and Rothkopf, Michael H and Stewart Jr, William, "Dispatchable Transmission in RTO Markets," *IEEE Transactions on Power Systems*, vol. 20, no. 1, pp. 171–179, 2005.

[10] Hogan, William W, "Electricity Market Restructuring: Reforms of Reforms," *Journal of Regulatory Economics*, vol. 21, no. 1, pp. 103–132, 2002.

[11] Chao, Hung-po and Peck, Stephen and Oren, Shmuel and Wilson, Robert, "Flow-Based Transmission Rights and Congestion Management," *The Electricity Journal*, vol. 13, no. 8, pp. 38–58, 2000.

[12] Alomoush, MI and Shahidehpour, SM, "Generalized Model for Fixed Transmission Rights Auction," *Electric Power Systems Research*, vol. 54, no. 3, pp. 207–220, 2000.

[13] Chandley, John D and Hogan, William W, "Independent Transmission Companies in a Regional Transmission Organization," *Center for Business and Government, Harvard University, Cambridge, MA*, vol. 8, 2002.

[14] Fisher, Emily B and O'Neill, Richard P and Ferris, Michael C, "Optimal Transmission Switching," *IEEE Transactions on Power Systems*, vol. 23, no. 3, pp. 1346–1355, 2008.

[15] Hedman, Kory W and Oren, Shmuel S and ONeill, Richard P, "Optimal Transmission Switching: Economic Efficiency and Market Implications," *Journal of Regulatory Economics*, vol. 40, no. 2, pp. 111–140, 2011.

[16] Wolak, Frank A, "Alternatives to Implementing an Locational Marginal Pricing Market," 2004.

[17] Hogan, William W, "Independent System Operator (ISO) for a Competitive Electricity Market," *Center for Business and government. JF Kennedy School of Gaverment. Harvard University*, 1998.

[18] O'Neill, Richard P and Helman, Udi and Hobbs, Benjamin F and Stewart, William R and Rothkopf, Michael H, "A Joint Energy and Transmission Rights Auction: Proposal and Properties," *IEEE Transactions on Power Systems*, vol. 17, no. 4, pp. 1058–1067, 2002.

[19] Park, Chan S and Valenzuela, Jorge and Halpin, Mark and Sozer, Sevin and Kaymaz, Pinar, "Pricing Transmission Congestion in Electric Power Networks," *Auburn University.[Online]. Available: http://www. eng. auburn. edu/˜ jvalenz/NSFLMP/CMU2004Paper. pdf*, 2004.

[20] Joskow, Paul L, "Restructuring, Competition and Regulatory Reform in the US Electricity Sector," *The Journal of Economic Perspectives*, vol. 11, no. 3, pp. 119–138, 1997.

[21] Juliana Brint, "FTR Funding Levels, Mechanisms Vary by ISO: Analysis," *Platts Megawatt Daily*, vol. 19, no. 58, 03 2014, LexisNexis Academic. [Online]. Available: http://www.lexisnexis.com/hottopics/lnacademic

[22] Alderete, Guillermo Bautista, "FTRs and Revenue Adequacy," in *Financial Transmission Rights*. Springer, 2013, pp. 253–270.

[23] Sarkar, V and Khaparde, SA, "Introduction to Multidimensional Financial Transmission Rights," *IEEE Transactions on Power Systems*, vol. 23, no. 1, pp. 47–57, 2008.

[24] "Business Practice Manual for Congestion Revenue Rights, Version 20," Aug 2016. [Online]. Available: https://bpmcm.caiso.com/BPM%20Document%20Library/Congestion%20Revenue%20Rights/Congestion%20Revenue%20Rights%20BPM%20Version%2020_clean.docx

[25] Chmielewski, Brian, "2015/2016 Monthly FTR Auction Transmission Outage Modeling," Dec 2015. [Online]. Available: http://www.pjm.com/~/media/markets-ops/ftr/ftr-allocation/monthly-ftr-auctions/2015-2016-monthly-transmission-outages-that-may-cause-infeasibilities.ashx

[26] "ISO New England Manual for Financial Transmission Rights Manual M-06, Revision: 10," Oct 2012. [Online]. Available: https://www.iso-ne.com/static-assets/documents/2017/02/m06_financial-transmission-rights_rev10_20121001.pdf

[27] "MISO ARR/FTR Modeling Practices MO-OP-019-r5," Apr 2016. [Online]. Available: https://www.misoenergy.org/Library/Repository/Report/FTR_ARR/ARR-FTR%20Modeling%20Practices%20Procedure.pdf

[28] "AFC/ATC Calculation Procedure PL-MOD-0001," Mar 2006. [Online]. Available: http://www.oatioasis.com/BREC/BRECdocs/AFC-ATC.pdf

[29] "Open Access Transmission Tariff," Dec 2012. [Online]. Available: http://www.oasis.oati.com/EES/EESDocs/bus_prac.html

[30] "Seams AFC Support: Available Transfer Capability Implementation Document (ATCID)," Nov 2015. [Online]. Available: http://www.oatioasis.com/SWPP/SWPPdocs/ATCID_V3.1_110615.pdf

[31] "Available Transfer Capability Implementation Document (ATCID) PJM

Effective Date: January 20, 2017," Jan 2017. [Online]. Available: http://ftp://ftp.pjm.com/oasis/ATCID.pdf

[32] "Entergy Available Transfer Capability Implementation Document," Aug 2013. [Online]. Available: http://www.oatioasis.com/EES/EESdocs/ATCID.pdf

[33] "NERC ATCT Drafting Team," Nov 2005. [Online]. Available: http://www.nerc.com/pa/Stand/MOD%20V0%20Revision%20RF%20DL/atctdt-1105cca.pdf

[34] "Available Transfer Capability Implementation Document (ATCID)," Mar 2016. [Online]. Available: http://www.pjm.com/markets-and-operations/etools/oasis/atc-information.aspx

[35] "PJM Manual 2: Transmission Service Request, Revision: 13." [Online]. Available: http://www.pjm.com/~/media/documents/manuals/m02.ashx

[36] "CRR Issues Paper," May 2007. [Online]. Available: https://www.caiso.com/Documents/CRRIssuesPaper-CoveringTopics-befiledinJuly2007%E2%80%93-18-May-2007.pdf

[37] Blumsack, Seth, "Network Decomposition via Graph Theory," working paper, available at www. andrew. cmu. edu/˜ sblumsac/decomp. pdf, Tech. Rep., 2006.

[38] Wu, Felix and Varaiya, Pravin and Spiller, Pablo and Oren, Shmuel, "Folk

Theorems on Transmission Access: Proofs and Counterexamples," *Journal of Regulatory Economics*, vol. 10, no. 1, pp. 5–23, 1996.

[39] Braess, Dietrich and Nagurney, Anna and Wakolbinger, Tina, "On a Paradox of Traffic Planning," *Transportation science*, vol. 39, no. 4, pp. 446–450, 2005.

[40] Drive, Dynamic, "FERC: Landmark Orders - Order No. 888," 2005. [Online]. Available: https://www.ferc.gov/legal/maj-ord-reg/land-docs/order888.asp

[41] ——, "FERC: Landmark Orders - Order No. 889," 2005. [Online]. Available: https://www.ferc.gov/legal/maj-ord-reg/land-docs/order889.asp

[42] Kelly, Kevin and Henderson, J Stephen and Nagler, Peter A and Eifert, Mark, *Some Economic Principles for Pricing Wheeled Power.* Citeseer, 1987.

[43] Sioshansi, Fereidoon P, *Competitive Electricity Markets: Design, Implementation, Performance.* Elsevier, 2011.

[44] Singh, HARRY, "Transmission Markets, Congestion Management & Investment," *Competitive Electricity Markets: Design, Implementation, Performance*, pp. 141–178, 2008.

[45] "DOCKET NO. 10-011-U, Compliance Testimony Of Todd Hillman," Oct 2013. [Online]. Available: http://www.apscservices.info/pdf/10/10-011-u_1030_1.pdf

[46] Bykhovsky, Alex and James, Douglas A and Hanson, Charity A, "Introduction of Option Financial Transmission Rights into the New England Market," in

IEEE Power Engineering Society General Meeting, 2005. IEEE, 2005, pp. 237–242.

[47] "FTR Design as Implemented September 2002, R1.0," 2002. [Online]. Available: https://www.transpower.co.nz/sites/default/files/plain-page/attachments/transpower-ftr-design-R1-0.pdf

[48] Hogan, William W, "Contract Networks for Electric Power Transmission," *Journal of Regulatory Economics*, vol. 4, no. 3, pp. 211–242, 1992.

[49] ——, "Financial Transmission Rights, Revenue Adequacy and Multi-Settlement Electricity Markets," *unpublished.[Online]. Available Harvard University web site: http://www. hks. harvard. edu/fs/whogan/Hogan_FTR_Rev_Adequacy_*, vol. 31813, 2013.

[50] Osipovich, Alexander, "FTR Underfunding Leaves PJM Power Traders out of Pocket," Mar 2014. [Online]. Available: http://www.risk.net/energy-risk/feature/2332516/ftr-underfunding-leaves-pjm-power-traders-out-of-pocket

[51] Lesieutre, Bernard C and Hiskens, I and others, "Convexity of the Set of Feasible Injections and Revenue Adequacy in FTR Markets," *IEEE Transactions on Power Systems*, vol. 20, no. 4, pp. 1790–1798, 2005.

[52] ISO-New-England. (2017) Manuals - ISO New England. [Online]. Available: https://www.iso-ne.com/participate/rules-procedures/manuals

[53] "2014 State of the Market Report for the Miso Electricity Markets," 2017. [Online]. Available: https://www.potomaceconomics.com/wp-content/uploads/2017/02/2014-State-of-the-Market-Report.pdf

[54] Drive, Dynamic, "FERC: Industries - RTO/ISO," 2013. [Online]. Available: https://www.ferc.gov/industries/electric/indus-act/rto.asp

[55] A. rights reserved. (1999) Pjm history. [Online]. Available: http://www.pjm.com/about-pjm/who-we-are/pjm-history.aspx

[56] "PJM Has Power Supplies Ready to Keep Consumers Cool This Summer/ page 2 of 2," Tech. Rep., 2012. [Online]. Available: http://www.pjm.com/\textasciitidle/media/about-pjm/newsroom/2015-releases/20150518-pjm-2015-summer-assessment.ashx

[57] Sahni, Mandhir and Jones, Richard and Cheng, Yunzhi, "Locational Marginal Price Forecasting and Predictive Operations in US Power Markets," 2012.

[58] Fan, Zhenyu and Horger, Tim and Bastian, Jeff, "Current and Emerging Challenges in PJM Energy Market," in *de Transmission and Distribution Conference and Exposition*, 2010.

[59] FTR Auction, "Report to the Federal Energy Regulatory Commission Market Monitoring Unit," Tech. Rep., 2000. [On-

line]. Available: http://www.monitoringanalytics.com/reports/Reports/2000/080100-ftr-market-report-with-charts.pdf

[60] PJM, "RTO FTR Funding," 2016 (accessed September 5, 2016). [Online]. Available: http://www.pjm.com/-/media/markets-ops/ftr/ftr-credit.ashx?la=en

[61] "PJM Interconnection, L.L.C., Proposed Modifications to ARR and FTR Provisions, Docket No. EL16-6-000," 2015. [Online]. Available: http://pjm.com/media/documents/etariff/FercDockets/1658/20151019-el16-6-000.pdf

[62] Economics, Potomac, "2010 State of the Market Report for the MISO Electricity Markets," 2011 (accessed September 5, 2016). [Online]. Available: https://www.potomaceconomics.com/uploads/midwest_reports/2010_State_of_the_Market_Report_Final.pdf

[63] ——, "2013 State of the Market Report for the MISO Electricity Markets," 2014 (accessed September 5, 2016). [Online]. Available: https://www.potomaceconomics.com/uploads/midwest_reports/2013%20SOM_Analytic%20Appendix_Final.pdf

[64] ——, "2014 State of the Market Report for the MISO Electricity Markets," 2015 (accessed September 5, 2016). [Online]. Available: https://www.potomaceconomics.com/uploads/midwest_reports/2014_SOM_Report-Appendix_Final.pdf

[65] ——, "2015 State of the Market Report for the MISO Electricity Markets," 2016 (accessed September 5, 2016). [Online]. Available: https://www.potomaceconomics.com/uploads/midwest_reports/2015_SOM_Main_Body_Final_Rev.pdf

[66] MISO, "Financial Transmission Rights Update, Markets Committee of the Board of Directors," 2014 (accessed September 5, 2016). [Online]. Available: https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/FTRWG/2015/20150114/20150114%20FTRWG%20Item%2005%2020141210%20Markets%20Committee%20of%20the%20BOD%20Item%2004%20FTR%20Funding.pdf

[67] Alderete, Guillermo Bautista, "Implementation and Evolution of the Congestion Revenue Right Market in California," in *IEEE PES General Meeting*. IEEE, 2010, pp. 1–6.

[68] Department of Market Monitoring California ISO, "2010 Annual Report on Market Issues and Performance," 2011 (accessed September 16, 2016). [Online]. Available: http://www.caiso.com/Documents/2010AnnualReportonMarketIssuesandPerformance.pdf

[69] ——, "2013 Annual Report on Market Issues and Performance," 2014 (accessed September 16, 2016). [Online]. Available: http://www.caiso.com/Documents/2013AnnualReport-MarketIssue-Performance.pdf

[70] ——, "2015 Annual Report on Market Issues and Performance," 2016 (accessed September 16, 2016). [Online]. Available: http://www.caiso.com/Documents/2015AnnualReportonMarketIssuesandPerformance.pdf

[71] Market Monitoring Unit for the New York ISO, "2010 State of the Market Report for the New York ISO Markets," 2015 (accessed September 6, 2016). [Online]. Available: https://www.potomaceconomics.com/uploads/nyiso_reports/NYISO_2010_Final.pdf

[72] ——, "2011 State of the Market Report for the New York ISO Markets," 2012 (accessed September 6, 2016). [Online]. Available: https://www.potomaceconomics.com/uploads/nyiso_reports/NYISO_2011_SOM_Report-Final_4-18-12.pdf

[73] ——, "2012 State of the Market Report for the New York ISO Markets," 2013 (accessed September 6, 2016). [Online]. Available: https://www.potomaceconomics.com/uploads/nyiso_reports/NYISO_2012_SOM_Report_2013-04-17.pdf

[74] ——, "2013 State of the Market Report for the New York ISO Markets," 2014 (accessed September 6, 2016). [Online]. Available: https://www.potomaceconomics.com/uploads/nyiso_reports/NYISO_2013_SOM_Report.pdf

[75] ——, "2014 State of the Market Report for the New York ISO Markets," 2015 (accessed September 6, 2016). [Online].

Available: http://www.nyiso.com/public/webdocs/markets_operations/documents/Studies_and_Reports/Reports/Market_Monitoring_Unit_Reports/2014/NYISO2014SOMReport__5-13-2015_Final.pdf

[76] ——, "2015 State of the Market Report for the New York ISO Markets," 2016 (accessed September 6, 2016). [Online]. Available: http://www.nyiso.com/public/webdocs/markets_operations/documents/Studies_and_Reports/Reports/Market_Monitoring_Unit_Reports/2015/NYISO%202015%20SOM%20Report_5-23-2016-CORRECTED.pdf

[77] Economics, Potomac, "2010 Assessment of the ISO New England Electricity Markets," 2011 (accessed September 5, 2016). [Online]. Available: https://www.potomaceconomics.com/uploads/isone_reports/ISONE_2010_IMMU_Report_Draft_Final_June-11.pdf

[78] ——, "2011 Assessment of the ISO New England Electricity Markets," 2012 (accessed September 5, 2016). [Online]. Available: https://www.potomaceconomics.com/uploads/isone_reports/ISONE_2011_EMMU_Report_Final_June_2012.pdf

[79] ——, "2012 Assessment of the ISO New England Electricity Markets," 2013 (accessed September 5, 2016). [Online]. Available: https://www.potomaceconomics.com/uploads/isone_reports/ISONE_2012_EMM_Report_Final.pdf

[80] ——, "2013 Assessment of the ISO New England Electricity Markets," 2014 (accessed September 5, 2016). [Online]. Available: https://www.potomaceconomics.com/uploads/isone_reports/isone_2013_emm_report_final_6_25_2014.pdf

[81] ——, "2014 Assessment of the ISO New England Electricity Markets," 2015 (accessed September 5, 2016). [Online]. Available: https://www.potomaceconomics.com/uploads/isone_reports/isone_2014_emm_report_6_16_2015_final.pdf

[82] ——, "2015 Assessment of the ISO New England Electricity Markets," 2016 (accessed September 5, 2016). [Online]. Available: https://www.potomaceconomics.com/uploads/isone_reports/ISONE_2015_EMM_Report_final_6-14-16.pdf

[83] "Texas Nodal Market Management Systems (MMS) Requirement Specification for Day-Ahead Market (DAM) and Supplemental Ancillary Service Market," November 2006. [Online]. Available: http://www.ercot.com/content/meetings/tptf/keydocs/2006/1106/19a1-MMS_Requirement_Specification_For_DAM_and_SASM_Ver.0.9.doc

[84] Carrie Bivens, "CRR Shortfall (Updated) Joint CWG/MCWG Presentation," August 2013. [Online]. Available: http://ercot.com/content/meetings/creditwg/keydocs/2013/0828/Item_6_CWG_CRR_Shortfall_Update_080513.ppt

[85] SPP Market Monitoring Unit, “SPP 2014 State of the Market,” 2015 (accessed September 5, 2016). [Online]. Available: https://www.spp.org/markets-operations/integrated-marketplace/

[86] ——, “SPP 2015 State of the Market,” 2016 (accessed September 5, 2016). [Online]. Available: https://www.spp.org/markets-operations/integrated-marketplace/

[87] Alsac, O and Bright, JM and Brignone, S and Prais, M and Silva, C and Stott, B and Vempati, N, “The Rights to Fight Price Volatility,” *IEEE Power and Energy Magazine*, vol. 2, no. 4, pp. 47–57, 2004.

[88] Evans, Lewis and Meade, Richard, “Economic Analysis of Financial Transmission Rights (FTRs) with specific reference to the Transpower proposal for New Zealand,” 2001.

[89] Hedman, Kory W and Oren, Shmuel S and O’Neill, Richard P, “Revenue Adequacy Constrained Optimal Transmission Switching,” in *System Sciences (HICSS), 2011 44th Hawaii International Conference*. IEEE, 2011, pp. 1–10.

[90] Oren, Shmuel and HEDMAN, K and ONEIL, R, “Optimal Transmission Switching: When Economic Efficiency and FTR Markets Collide,” in *Economics of Energy Markets Conference*, 2010.

[91] “Notice Inviting Comments on Establishing Long Term Transmission Rights

in Markets with Locational Pricing, Docket No. AD05-7-000," October 2015. [Online]. Available: https://www.ferc.gov/industries/electric/indus-act/rto/notice/05-11-05.pdf

[92] California ISO, "Congestion Revenue Rights Monthly Global De-Rate Factor," 2016 (accessed April 10, 2016). [Online]. Available: http://www.caiso.com/Documents/CRRMonthlyGlobalDe-RateFactor.xls

[93] Oren, Shmuel S, "Point to Point and Flow-Based Financial Transmission Rights: Revenue Adequacy and Performance Incentives," in *Financial Transmission Rights*. Springer, 2013, pp. 77–94.

[94] Bivens, Carrie, "CRR Update, August 18, 2016," 2016 (accessed December 10, 2016). [Online]. Available: http://www.ercot.com/content/wcm/key_documents_lists/102770/CMWG_081816.pptx

[95] Kumar, Ashwani and Srivastava, SC and Singh, SN, "Congestion Management in Competitive Power Market: A Bibliographical Survey," *Electric Power Systems Research*, vol. 76, no. 1, pp. 153–164, 2005.

[96] Sarkar, V and Khaparde, SA, "A Comprehensive Assessment of the Evolution of Financial Transmission Rights," *IEEE Transactions on Power Systems*, vol. 23, no. 4, pp. 1783–1795, 2008.

[97] Scwheppe, FC and Caraminis, MC and Tabors, RO and Bohn, RE, "Spot Pricing of Electricity," 1988.

[98] Hogan, William W, "Contract Networks for Electric Power Transmission," in *From Regulation to Competition: New frontiers in electricity markets.* Springer, 1994, pp. 175–199.

[99] HARVEY, SCOTT M and HOGAN, WILLIAM W and POPE, SUSAN L, "Transmission Capacity Reservations and Transmission Congestion Contracts," 1996.

[100] "NERC Operating Manual." [Online]. Available: http://www.nerc.com/comm/oc/operatingmanualdl/opman_june_15_2004.pdf

[101] Oren, Shmuel S and Spiller, Pablo T and Varaiya, Pravin and Wu, Felix, "Nodal Prices and Transmission Rights: A Critical Appraisal," *The Electricity Journal*, vol. 8, no. 3, pp. 24–35, 1995.

[102] Wood, Allen J and Wollenberg, Bruce F, *Power Generation, Operation, and Control.* John Wiley & Sons, 2012.

[103] Oren, Shmuel S, "Comments in FERC Docket No. RM01-12-000: The FGR vs. FTR Debate: Facts and Misconceptions," *Unpublished paper, Power Systems Engineering Research Center, University of Wisconsin.[216]*, 2002.

[104] Hogan, William W, "Flowgate Rights and Wrongs," *Center for Business and Government, Harvard University, Cambridge, MA*, 2000.

[105] Ruff, LR, "Flow-Gates, Contingency, Constrained Dispatch and FTRs," in *Energy Modeling Forum, Stanford University, Stanford. Available from http://www. stanford. edu/group/EMF/meet. Google Scholar*, 2000.

[106] Ruff, Larry E, "Flowgates vs. FTRs, and Options vs. Obligations," *Harvard University, aug*, 2000.

[107] Alvarado, Fernando L and Oren, Shmuel S, "A Tutorial on the Flowgates Versus Nodal Pricing Debate," in *PSERC IAB Meeting Tutorial*, 2000.

[108] Oren, Shmuel S, "More on Options vs. Obligations and FGRs vs. Pt. To Pt. FTRs," *Jornal, v*, vol. 7, no. 5, pp. 24–43, 2000.

[109] Tabors, Richard D, "Forward Markets for Transmission That Clear at LMP: A Hybrid Proposal," in *System Sciences, 2001. Proceedings of the 34th Annual Hawaii International Conference on.* IEEE, 2001, pp. 8–pp.

[110] ONeill, Richard P and Helman, Udi and Hobbs, Benjamin F and Rothkopf, Michael H and Stewart, William R, "A Joint Energy and Transmission Rights Auction on a Network with Nonlinear Constraints: Design, Pricing and Revenue Adequacy," in *Financial Transmission Rights.* Springer, 2013, pp. 95–127.

[111] Eldridge, Brent and ONeill, Richard P and Castillo, Anya, "Marginal Loss Calculations for the DCOPF," 2017.

[112] Harvey, Scott M and Hogan, William W, "Loss Hedging Financial Transmission Rights," *Center for Business and Government, Harvard University*, vol. 15, 2002.

[113] Bushnell, James B and Stoft, Steven E, "Electric Grid Investment under a Contract Network Regime," *Journal of Regulatory Economics*, vol. 10, no. 1, pp. 61–79, 1996.

[114] Pritchard, Geoffrey and Philpott, Andy, "On Financial Transmission Rights and Market Power," *Decision support systems*, vol. 40, no. 3, pp. 507–515, 2005.

[115] "TCC Obligations and Options," Tech. Rep. [Online]. Available: http://www.nyiso.com/public/webdocs/markets_operations/committees/bic_mswg/meeting_materials/2001-11-16/tcc_options_11_21_01.pdf

[116] Boyd, Stephen and Vandenberghe, Lieven, *Convex Optimization.* Cambridge university press, 2004.

[117] Philpott, Andy and Pritchard, Geoffrey, "Financial Transmission Rights in Convex Pool Markets," *Operations Research Letters*, vol. 32, no. 2, pp. 109–113, 2004.

[118] Rosellón, Juan and Kristiansen, Tarjei, *Financial Transmission Rights*. Springer, 2013.

[119] Oren, Shmuel S and Hedman, Kory W, "Revenue Adequacy, Shortfall Allocation and Transmission Performance Incentives in FTR/FGR Markets," in *Bulk Power System Dynamics and Control (iREP)-VIII (iREP), 2010 iREP Symposium*. IEEE, 2010, pp. 1–6.

[120] Rudkevich, Aleksandr M and Caramanis, Michael C and Goldis, Evgeniy A and Li, Xiaoguang and Ruiz, Pablo A and Tabors, Richard D, "Financial Transmission Rights in Changing Power Networks," in *2016 49th Hawaii International Conference on System Sciences (HICSS)*. IEEE, 2016, pp. 2326–2334.

[121] Hedman, Kory W and O'Neill, Richard P and Fisher, Emily Bartholomew and Oren, Shmuel S, "Optimal Transmission Switchingsensitivity Analysis and Extensions," *IEEE Transactions on Power Systems*, vol. 23, no. 3, pp. 1469–1479, 2008.

[122] ——, "Optimal Transmission Switching with Contingency Analysis," *IEEE Transactions on Power Systems*, vol. 24, no. 3, pp. 1577–1586, 2009.

[123] Hedman, Kory W and Ferris, Michael C and O'Neill, Richard P and Fisher, Emily Bartholomew and Oren, Shmuel S, "Co-Optimization of Generation Unit Commitment and Transmission Switching with N-1 Reliability," *IEEE Transactions on Power Systems*, vol. 25, no. 2, pp. 1052–1063, 2010.

[124] Hedman, Kory W and Oren, Shmuel S and O'Neill, Richard P, "A Review of Transmission Switching and Network Topology Optimization," in *2011 IEEE power and energy society general meeting.* IEEE, 2011, pp. 1–7.

[125] Hedman, Kory W and Oren, Shmuel S and ONeill, Richard P, "Flexible Transmission in the Smart Grid: Optimal Transmission Switching," in *Handbook of Networks in Power Systems I.* Springer, 2012, pp. 523–553.

[126] Barrows, Clayton and Blumsack, Seth and Bent, Russell, "Using Network Metrics to Achieve Computationally Efficient Optimal Transmission Switching," in *System Sciences (HICSS), 2013 46th Hawaii International Conference on.* IEEE, 2013, pp. 2187–2196.

[127] Lipka, Paula A and ONeill, Richard P and Oren, Shmuel S and Castillo, Anya and Pirnia, Mehrdad and Campaigne, Clay, "Optimal Transmission Switching Using the IV-ACOPF Linearization," *FERC staff technical paper*, 2013.

[128] Papavasiliou, Anthony and Oren, Shmuel S and Yang, Zhu and Balasubramanian, Pranav and Hedman, Kory, "An Application of High Performance Computing to Transmission Switching," in *Bulk Power System Dynamics and Control-IX Optimization, Security and Control of the Emerging Power Grid (IREP), 2013 IREP Symposium.* IEEE, 2013, pp. 1–6.

[129] Rangarajan, Rajes and Wang, Zongfei, "An Improved Simultaneous Feasibility

Test to Alleviate Revenue Inadequacy in FTR Markets," in *North American Power Symposium (NAPS), 2014*. IEEE, 2014, pp. 1–6.

[130] Fu, Yong and Li, Zuyi, "Different Models and Properties on LMP Calculations," in *2006 IEEE Power Engineering Society General Meeting*. IEEE, 2006, pp. 11–pp.

[131] Wood, Allen J and Wollenberg, Bruce F, "Power Generation, Operation, and Control," 1996.

[132] Wikipedia, "Braess' Paradox — Wikipedia, The Free Encyclopedia," 2016, [Online; accessed 21-September-2016]. [Online]. Available: https://en.wikipedia.org/w/index.php?title=Braess%27_paradox&oldid=740501674

[133] Easley, David and Kleinberg, J, "Modeling Network Traffic Using Game Theory," *Networks, Crowds, and Markets: Reasoning about a Highly Connected World*, pp. 229–247, 2010.

[134] "Wikimedia Commons," January 2012. [Online]. Available: https://commons.wikimedia.org/wiki/File:Braess_paradox_road_example.svg

[135] Bjørndal, Mette and Jørnsten, Kurt, "Investment Paradoxes in Electricity Networks," in *Pareto optimality, game theory and equilibria*. Springer, 2008, pp. 593–608.

[136] "Wikimedia Commons," May 2006. [Online]. Available: https://commons.wikimedia.org/wiki/File:Wheatstone_Bridge.svg

[137] YesEnergy,, "PowerSignals." [Online]. Available: http://www.yesenergy.com

[138] Kristov, Lorenzo, "California Independent System Operator Corporation Modeling Transmission Outages in the CRR Network Model," 2007, [Online; accessed 28-April-2013]. [Online]. Available: http://caiso.com/Documents/Presentation-ModelingTransmissionOutagesinCRRNetworkModel.pdf

[139] ——, "Modeling Transmission Outages in the CRR Network Model," Jun 2007. [Online]. Available: http://caiso.com/Documents/Presentation-ModelingTransmissionOutagesinCRRNetworkModel.pdf

[140] "Whitepaper for Congestion Revenue Rights Model Build Processes, Version 0.2," Jun 2013. [Online]. Available: http://www.ercot.com/content/meetings/cmwg/keydocs/2013/0605/ERCOT_Whitepaper_CRR_NetworkModelBuild_v0_2_June2013.doc

[141] "TCR Market Modeling Processes, Version 2.1," Jan 2016. [Online]. Available: https://www.spp.org/documents/21423/tcr%20market%20modeling%20processes_.pdf

[142] "MISO ARR/FTR Modeling Practices MO-OP-019-R5," April 2016. [On-

line]. Available: https://www.misoenergy.org/Library/Repository/Report/FTR_ARR/ARR-FTRModelingPracticesProcedure.pdf

[143] "FERC Order 888, Appendix D, Pro Forma Open Qccess, Transmission Tariff," April 1996. [Online]. Available: https://www.ferc.gov/legal/maj-ord-reg/land-docs/rm95-8-0aa.txt

[144] Ma, Xingwang and Sun, David I and Rosenwald, Gary W and Ott, AL, "Advanced Financial Transmission Rights in the PJM Market," in *Power Engineering Society General Meeting, 2003, IEEE*, vol. 2. IEEE, 2003.

[145] "ERCOT Market Information System," Jan 2015, accessed to MIS provided by registration as a Market Information System Registered Entity (IMRE) under Israel W Melendez, DUNS # 08-083-53337-8000. [Online]. Available: https://mis.ercot.com/pps/tibco/mis

[146] "NERC Map of U.S. Interconnections," 2017. [Online]. Available: https://energy.gov/sites/prod/files/styles/borealis_default_hero_respondlarge/public/hero_images/NERC_Interconnection_1A_010711.jpg?itok=bN7utjGi

[147] "Competition in Bilateral Wholesale Electric Markets: How Does It Work?" 2017. [Online]. Available: https://www.hks.harvard.edu/hepg/Papers/2016/BilateralMarketsWhitePaperFinal.pdf

[148] "ERCOT Market Education Congestion Revenue Rights," 2014. [On-

line]. Available: http://www.ercot.com/content/wcm/training_courses/53/crr_february2014.pdf

[149] Parmeshwaran, Vijay and Muthuraman, Kumar, "FTR-Option Formulation and Pricing," *Electric Power Systems Research*, vol. 79, no. 7, pp. 1164–1170, 2009.

[150] Blumsack, Seth and Lave, Lester B and Ilić, Marija, "A Quantitative Analysis of the Relationship between Congestion and Reliability in Electric Power Networks," *The Energy Journal*, pp. 73–100, 2007.

[151] Blumsack, Seth and Ilic, Marija and Lave, Lester B, "Separability and Independence of Congestion and Reliability: Theory and Simulations," in *Power Engineering Society General Meeting, 2007. IEEE.* IEEE, 2007, pp. 1–10.

[152] Blumsack, Seth and Ilić, Marija and Lave, Lester B, "Decomposing Congestion and Reliability," 2006.

[153] Blumsack, Seth and Ilić, Marija, "The Braess Paradox in Electric Power Systems," Working Paper, Carnegie Mellon University, Pittsburgh, Pennsylvania, Tech. Rep., 2006.

[154] Blumsack, Seth and Lave, Lester B and Ilić, Marija, "Topological Elements of Transmission Pricing and Planning," Draft Working Paper, Tech. Rep., 2006.

[155] Blumsack, Seth, "The Efficiency of Point-to-Point Financial Transmission Rights is Limited by the Network Topology," 2006.

[156] Blumsack, Seth A and Apt, Jay and Lave, Lester B, "Lessons from the Failure of US Electricity Restructuring," *The Electricity Journal*, vol. 19, no. 2, pp. 15–32, 2006.

[157] Blumsack, Seth, "Some Implications of Braess Paradox in Electric Power Systems," working paper, available at http://www. andrew. cmu. edu/˜ sblumsac/braess. pdf, Tech. Rep., 2006.

[158] "Texas Nodal: Congestion Revenue Rights System Conceptual System Design (B2), Version 2.1," September 2008. [Online]. Available: http://www.ercot.com/content/meetings/tptf/keydocs/2008/0922/15_crr_conceptual_system_design_b2_v2_1.doc

[159] "Treatment of PTP Obligations in the CRR Auction Presentation."

[160] "ERCOT Nodal Protocols Section 7: Congestion Revenue Rights," March 2017. [Online]. Available: http://www.ercot.com/content/wcm/current_guides/53528/07-030117_Nodal.doc

[161] (1996) Glossary - G. [Online]. Available: {http://www.ercot.com/glossary/g}

[162] Sorokin, A. and Rebennack, S. and Pardalos, P.M. and Iliadis, N.A. and Pereira, M.V.F., *Handbook of Networks in Power Systems I*, ser.

Energy Systems. Springer Berlin Heidelberg, 2012. [Online]. Available: https://books.google.com/books?id=xNj_dmLzS9YC

[163] "ERCOT Nodal Operating Guides, Section 5: Network Operations Modeling Requirements," January 2014. [Online]. Available: http://www.ercot.com/content/mktrules/guides/noperating/current/05-010114.doc

[164] Bell, Bradley, "CRR Model Building Process Presentation," 2011. [Online]. Available: http://www.ercot.com/content/meetings/other/keydocs/2011/20110609-Other/Item_1_-_CRR_Model_Building_Process.ppt

[165] Jirasek, Shawna and Garza, Beth, "Texas Nodal CRR Requirements, Overview of Requirements," September 2006. [Online]. Available: http://www.ercot.com/content/meetings/tptf/keydocs/2006/0911/07a-CRR_RequirementsPresentation_20060906.ppt

[166] Moseley, John D and Mago, Nitika V and Grady, W Mack and Santoso, Surya, "Lessons and Experiences in the Implementation of a Consolidated Transmission Modeling Data System at ERCOT," *IEEE Power and Energy Technology Systems Journal*, vol. 1, pp. 12–20, 2014.

[167] Haq, Enamul and Haller, Dagmar and Rahman, Khaled Abdul and Iverson, Becky, "Use of Common Information Model (CIM) in Electricity Market at California ISO," in *2011 IEEE Power and Energy Society General Meeting*. IEEE, 2011, pp. 1–6.

[168] Moseley, Johnathan David and others, "Consolidated Network Model Management System for ISO/RTO to Support Electrical Transmission System Model Data," Ph.D. dissertation, 2015.

[169] "Unified Power System Models through Integrated Topology Processing (ITP)." [Online]. Available: https://www.powerworld.com/files/PowerWorld-Integrated-Topology-Processing1.pdf

[170] Nagurney, Ladimer S and Nagurney, Anna, "Physical Proof of the Occurrence of the Braess Paradox in Electrical Circuits," *EPL (Europhysics Letters)*, vol. 115, no. 2, p. 28004, 2016.

[171] Sheskin, David J., *Handbook of Parametric and Nonparametric Statistical Procedures*, 4th ed. Chapman & Hall/CRC, 2007.

[172] "Business Practice Manual for Congestion Revenue Rights Version 20," August 2016. [Online]. Available: https://bpmcm.caiso.com/BPM%20Document%20Library/Congestion%20Revenue%20Rights/Congestion%20Revenue%20Rights%20BPM%20Version%2020_clean.docx

[173] Zaborszky, John and Whang, Keh-Wen and Prasad, Krishna, "Fast Contingency Evaluation Using Concentric Relaxation," *IEEE Transactions on Power Apparatus and Systems*, no. 1, pp. 28–36, 1980.

[174] Brandwajn, V and Lauby, MG, "Complete Bounding Method for AC Contin-

gency Screening," *IEEE Transactions on Power Systems*, vol. 4, no. 2, pp. 724–729, 1989.

Vita

Israel W. Melendez is a graduate of Calhoon MEBA Marine Engineering School where he received a diploma, Marine Engineering in 1983. In 2000, he received a Bachelor degree in Electrical Engineering from Johns Hopkins University and was inducted into the Tau Beta Pi honor society. Israel Melendez received an Executive Masters of Business Administration in 2003 and a Master of Science in Finance in 2009 from Loyola University in Maryland. Israel enrolled in the Department of Geography and Environmental Engineering Ph.D. program at Johns Hopkins University in 2009 and in 2011, he received Masters of Science in Engineering degree from Johns Hopkins University. Israel is currently a doctoral candidate at Johns Hopkins University.

Israel Melendez started his career at the Baltimore, Gas, and Electric company in 1984. He worked in various operations and supervisory positions for the power production unit and as an engineer in the electrical controls and modification engineering unit. In 2001, Israel began at Constellation Power Source (CPS) in the Asset Operations group. CPS later became Constellation Energy Commodities Group (CECG). In 2004, he became Vice President of Grid Optimization Group a group that models and forecast congestion to inform CECG's trading and commercial decisions. In 2012, he became Manager of Transmission Analytics after Exelon Corporation acquired Constellation.

Since 2001, Israel has served on various market stakeholder committees including: In ERCOT, Reliability Operations Subcommittee (ROS), Operations Working Group (OWG), Congestion Management Working Group (CMWG), Regional Planning Group (RPG). At MISO, Market Subcommittee and was the first vice chair of the Data Transparency Working Group. Israel served on the NERC committees: Planning Committee, Transmission Issues Subcommittee and was a member of the Available Transmission Capacity drafting team. He is currently serving on Florida's Reliability Coordination Council's (FRCC) Regional Entity - Board of Directors. Additionally, he served six years on the American Statistical Association's Committee on Energy Statistics to the Energy Information Administration (EIA).